REPRESENTING VARIABLE RENEWABLE ENERGIES IN LONG-TERM ENERGY SYSTEMS MODELLING

Development of a modelling tool for providing initial consultation to German federal states

Master's thesis (30 ECTS)

Utrecht University
Faculty of Geosciences

1st reader: Prof. Dr. Wolfgang Eichhammer
2nd reader: Dr. Robert Harmsen

In cooperation with: Fraunhofer Institute for Systems and Innovation Research ISI
Internship supervisor: Prof. Dr. Rainer Elsland

Date of submission: 16.11.2018

Tim Mandel

Study programme: M.Sc. Sustainable Development (Energy & Materials)
Student ID: 6031455
E-mail: t.d.mandel@students.uu.nl

Acknowledgements

There were a multitude of individuals who greatly helped me to arrive at this point. First, I would like to thank my academic supervisor at Utrecht University, Prof. Dr. Wolfgang Eichhammer, who inspired me to undertake the internship at Fraunhofer ISI. His valuable advice and critical thoughts contributed decisive impulses to my work.

I would also like to give a special thank you to my supervisor at Fraunhofer ISI, Prof. Dr. Rainer Elsland, who has been an unfailing source of encouragement, advice and reassurance throughout the project. Our discussions greatly helped me to focus on the essential aspects of my subject and to remain critical about by own work. I also wish to thank the colleagues at Fraunhofer ISI for their helpful comments and recommendations in the realisation of the project.

Finally, I must express my sincere gratitude to my friends and family for their constant support and patience. None of this would have been possible without you giving me the opportunities and experiences that led me to where I am today.

Abstract

With increasing deployment of variable renewable energies (VRE), as well as ongoing structural changes in energy demand, decision-makers in German federal states must make difficult decisions with regard to long-term power supply investments and policy design. Model-based scenario analyses are a common means to derive long-term strategies in this matter. However, considering their typically high computational complexity and data needs, established modelling tools can be considered inappropriate for providing initial consultation, i.e. a first approximation of developments necessary for attaining certain long-term outcomes. For this reason, the present study investigates to what extent a model with reduced levels of detail can yield plausible results regarding the dynamics of VRE-based power supply and energy demand.

The centrepiece of the study is the development of the novel modelling tool 'FederalPlan'. As for energy demand, it features a bottom-up accounting framework for projecting energy needs in four major demand sectors. Exogenous parameters include fuel and technology substitution towards electrification, improvements in energy efficiency, as well as socio-economic effects. These projections are used for endogenous projections of future electrical load curves and demand-side-management (DSM) potentials. Considering power supply, the model optimises investments and dispatch of generators and flexibility options, in order to minimise power system costs from a socio-economic perspective. Technologies are selected from a diverse portfolio of thermal power plants, cogeneration plants, storage facilities, DSM interventions, as well as power-to-gas and power-to-heat converters. One model run results in a cost-effective power supply configuration at given parameters and policy constraints for a single target year.

Robustness of the model outputs is evaluated by performing a comparative assessment with an established model-based scenario study for the state of Baden-Württemberg. Under equal boundary conditions, the two models match with regard to the deployment of power-to-heat and CHP plants in the target year 2050. Deviations include the extent and composition of reserve capacity needed to cover system load. Accordingly, using either of the two approaches, policy recommendations may differ in providing initial consultation to decision-makers. In addition to the model comparison, sensitivity analyses are carried out for the FederalPlan tool. Among other parameters, the hourly shape of the endogenously modelled load curve is found to have an influence on the deployment and dispatch of power plants and flexibility options. Overall, the modelling tool is considered to yield reasonable results. Given its low computational complexity and data needs, it may proof useful for providing initial consultation to federal state decision-makers with regard to long-term planning of power supply and associated policy design.

Keywords: *energy systems modelling, Germany, variable renewable energies, power supply, flexibility*

Contents

List of Figures

List of Tables

Abbreviations and acronyms

CAES	Adiabatic compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CNG	Compressed natural gas
DC	Direct current
DR	Demand response
DSM	Demand side management
EPM	Long-term energy planning model
ETS	Emissions Trading System
EUA	European Emission Allowance
EU	European Union
EV	Electric vehicle
GHG	Greenhouse gas
GIS	Geographic information system
HVCD	High voltage direct current
ICT	Information and communications technology
IRENA	International Renewable Energy Agency
LCOE	Levelised cost of electricity
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
P2G	Power-to-gas
P2H	Power-to-heat
P2X	Power-to-X
PCM	Production cost model
PDA	Partial decomposition approach
PHES	Pumped hydro-electric storage
PV	Photovoltaics
TCS	Trade, commerce, services
VBA	Visual Basic for Applications
VRE	Variable renewable energies

1. Introduction

The following chapter establishes the general scope of the present study. First, Section 1.1 outlines the role of scenarios and models in long-term energy system planning for German federal states. Subsequently, Section 1.2 provides an overview of relevant academic literature and identifies three research gaps in the field of study. Finally, Section 1.3 states the objective of the research and its corresponding research question.

1.1. Background

Spurred by ambitious national commitments, international agreements and rapid technological progress, national governments increasingly rely on renewable energy to meet their demand for energy and to mitigate greenhouse gas (GHG) emissions [2,3]. In recent years, Germany has undergone a rapid expansion of renewable energy capacities. In 2014, renewables accounted for around 28 percent in gross electricity consumption, with more than half of this electricity being produces by wind power and photovoltaics (PV) [4]. These technologies are frequently referred to as variable renewable energy sources (VRE) because their power generation is intermittent in response to weather conditions, location specific, and only predictable to a limited extent [3]. VRE are expected to have distinct techno-economic impacts on power system operation, including the need for firm generation capacity, flexibility, transmission capacity as well as enhanced voltage and frequency control [2,5–7]. As outlined in its 2010 Energy Concept ('Energiekonzept') [8], the German government aims to substantially convert the country's energy system from fossil fuels to renewables by 2050. Accordingly, it can be anticipated that power supply in Germany will be subject to extensive techno-economic challenges [2,4].

FIGURE 1. Federal states of Germany. Source: author's own, based on [1].

While the integration of VRE in power systems is already a challenge by itself, further complexity arises with regard to the evolution of energy consumption in the different demand sectors. Commonly referred as the "coupling" of sectors, future power demand in Germany is expected to increase significantly over the upcoming decades, while being subject to structural changes. This is mostly attributed to the growing electrification of processes in the heating and the transport sector, including the use of heat pumps and electric vehicles

[7,9,10].[1] In order to balance VRE generation and power demand in the short term, the German power system already features flexible power plants as well as pumped hydro-electric plants. In the upcoming decades, other technologies are likely to become cost-efficient. Batteries in electric vehicles can be charged when there is excess power from wind and PV. Conversion of electricity into hydrogen, methane or heat offer storage solutions over long periods of time. Flexible power plants could not only use coal or natural gas as their primary fuel, but also biogas or geothermal energy. Likewise, electricity demand can be steered via so-called demand side management (DSM) [2,4,6].

However, this transition process is associated with large future uncertainties, including the exact evolution of power demand in different sectors, improvements in energy efficiency, fuel source availability and cost, technological advances and environmental change [6]. Against this increasingly complex background, decision-makers in government and planning agencies must make difficult choices related to energy and environmental policy as well as energy technology investment [12]. In Germany, public policies are not only designed and shaped on a central state level, but also in the sixteen federal states ('Bundesländer') (Figure 1). Within the country's political system, federal state government and authorities have notable competences in designing energy policy[2] and determining own energy policy targets. As such, targets range from renewable energy capacity expansion to greenhouse gas emissions reduction targets.[3] Accordingly, federal states are considered an important contributor to the country's overall transition towards a future low-carbon energy system [15,16].

Decision makers, both at national and federal state level, frequently rely on scenario studies that allow them to assess cost-effective investment pathways, to gauge the impact of their decisions and to evaluate if and how their policy objectives can be attained [17–19].[4] Such scenario analyses

---

[1] In more systematic terms, structural change in power demand can be categorised with regard to (i) fuel substitution (e.g. replacement of blast furnace by electric arc furnace in the steel industry), (ii) technology substitution (e.g. penetration of heat pumps which replace night storage heaters), (iii) diffusion of energy efficient technologies (e.g. efficient household appliances), (iv) new processes (e.g. electric vehicles), and (v) macro-economic impacts (e.g. changes in economic activity or population) [11].

[2] Most notably, federal states have comprehensive legislative power in the field of spatial planning – which is highly relevant with regard to renewable energy siting and deployment – and building-related heating system regulation. See [13,14] for comprehensive reviews on the distribution of legislative powers between the German federal and state governments in the field of energy policy.

[3] Appendix 7.1 provides a comprehensive overview of existing energy and climate policy targets in German federal states.

[4] Research commonly defines scenarios as a range of possible future situations and distinguishes three categories of scenarios [20–22]: 'Forecast' or 'baseline' scenarios aim to predict future developments, based on historical trends and the effect of current policy. 'Exploratory' scenarios take into account the effect new

require computer models that reflect the essential interrelations between the elements of the energy system [17,22–24].[5] Designed by engineers, economists and planners, these models operate upon input data and assumptions, so called exogenous variables. Based on these variables, target values are calculated through the model, referred to as endogenous variables. Taken together, the numerical assumptions and calculations result in a range of possible scenarios that can substantiate decision making and provide policy-relevant insight [6,12,18,22,26,27].[6]

Typically, long-term energy planning models (EPM) are employed to generate such scenarios by analysing the evolution of the energy system over a long-term perspective of 20 to 40 years [3,25]. Prominent examples of EPMs are LEAP [28], MARKAL [29], and OSeMOSYS [2,6,30]. In an integrated manner, EPMs examine energy demand in different sectors, the transformation chain, as well power supply dynamics and cross-border trade [31]. Model outputs typically include the optimal portfolio of supply technologies over time, total system cost, primary and final energy consumption as well as corresponding emissions of greenhouse gases [12].

Due to their focus on long-term transitions as well as computational constraints, EPMs have limited levels of temporal, technical and spatial detail, and thereby do not take explicit account of the unique properties of VRE supply and power demand. For this purpose, a separate suite of production cost models (also referred to as dispatch models) and static grid models exist, which are specifically designed to investigate the short-term characteristics of the power sector, including unit commitment and voltage control [2,3,32,33]. Nonetheless, research is increasingly investigating novel methodologies that enable EPMs to better capture these features without becoming computationally unwieldy. These promising approaches include time series aggregations, parametrisations and model couplings [2,3,5].

1.2. Problem definition and research gaps

Using EPMs to represent the techno-economic challenges associated with VRE on a German federal state level is subject to multiple research gaps. These include i) generally, an inadequate consideration of VRE properties in existing scenario analyses, ii) a lack of modelling tools suitable

---

policy as well as surprising events. Finally, 'normative' or 'storyline' scenarios are based on an anticipated vision of the future and map out a range of actions to reach strategic objectives.

[5] For the sake of clarity, a distinction is made between energy models and modelling tools. A model is referred to as a set of mathematical equations with parameters, equipped with an algorithm to solve the equations. Modelling tools are graphical interfaces in a software package that help users handle the equations and data of a model [2,25].

[6] The merits of using energy models to inform energy policy-making are discussed comprehensively in research literature [2]. For instance, Mai et al. [21] elaborate on how energy scenarios and models are used to guide decision making under uncertainty. Moreover, they describe typical pitfalls in interpreting scenarios and underline that scenarios are not expected to predict the future.

for providing so-called initial consultation to federal state decision makers, and iii) a poor level of transparency in established scenario studies.

(I) Inadequate consideration of VRE properties in federal state scenario analyses

The techno-economic challenges associated with VRE are not always adequately addressed in long-term scenario analyses for German federal states. For example, Weber et al. [34] investigate future scenarios for Bavaria in the target year 2050. While their analyses focusses on the development of final energy consumption in different demand sectors, the representation of the power system remains highly stylized, with no explicit consideration of VRE-related integration challenges. Similar simplifications are made in scenario studies for Lower Saxony [35] and Rhineland-Palatinate [36]. Both studies assume a number of yearly full load hours for VRE generators while short-term mismatches between electricity supply and demand seem to be disregarded. Further published studies with stylized or neglected consideration of VRE-related integration challenges on a federal state level include [37–40].

Ultimately, ignoring the unique properties of VRE in long-term planning models can result in mistaken signals regarding system costs, greenhouse gas abatement potentials and the ability of power systems to accommodate VRE. As argued by multiple authors [3,6,7], a low level of temporal, technical and spatial detail in models applied can either favour or disfavour VRE deployment. For high penetrations of VRE, a low level of detail leads to an overestimation of the value of baseload technologies and VRE sources, while the value of flexible generation technologies is underestimated. In turn, by imposing upper limits on VRE shares or by fixing flexibility requirements, the low level of detail can overly restrict the deployment of VRE. As a result, the efforts required to achieve GHG reduction targets can be either significantly under- or overestimated [2,3].

Besides the overall consideration of VRE properties, also a general lack of diversity is evident with regard to scenario studies on a federal state level. While, for instance, Baden-Württemberg can rely on several competing scenario studies, only one scenario study was found for North Rhine-Westphalia. Considering the literature on model intercomparisons [20,21,41], it is likely that alternative models working with different parametrisations, boundaries and assumptions will suggest different degrees of policy effort needed to promote renewable energies and to abate GHG emissions in federal states [20,42].[7] In consequence, more long-term scenario studies should

[7] For instance, Fawcett et al. [43] compare 22 reference (BAU) scenarios for primary energy consumption in the U.S. based on five different models. Values for primary energy consumption diverge by up to 30 percent and respective fuel shares differ considerably, especially with respect to carbon capture and storage (CCS) technology [21]. Similarly, a model intercomparison project for Germany, comparing eight energy models with respect to climate mitigation policy, finds similar disparities in model outcomes [44].

be conducted for German federal states, with particular emphasis on the techno-economic impacts of VRE integration in future power systems.

(II) Lack of suitable modelling tools for initial consultation at a federal state level

Established long-term energy planning models (EPM) can be considered unsuitable for providing so-called initial consultation to decision-makers at a German federal state level. Initial consultation can be understood as a starting step in performing scenario studies commissioned by clients in politics, industry and non-governmental organisations. Its purpose is to gauge the major influencing factors for certain developments – such as socio-economic trends, technology costs and fuel prices – and to enable decision makers to comprehend the consequences of their actions in a quick and stylised manner before performing more elaborate modelling studies. In this way, initial consultation can allow for a better understanding of technology alternatives and related political decisions [20,21,45,46].

In this regard, established EPMs have two shortcomings – comprehensive data needs and computational complexity [42,47,48]. Data needs arise from a high degree of technical detail, resulting in a lengthy parametrisation and calibration process.[8] Considering that datasets of sufficient disaggregation and quality are rare for German federal states [50],[9] often collection and maintenance of these datasets becomes a challenge unto itself, which often results in periods of several months to perform modelling studies [21,49,54]. With respect to computation time, models taking detailed account of the temporal and spatial properties of VRE frequently run linear or mixed-integer optimisation methods that are numerically complex and thus time-intensive [3,7,55].[10] Accordingly, as stated above, scenario studies performed for federal state decision makers frequently make problematic simplifications with regard to the complexity of variable renewable energies, in order to avoid both data needs and computational complexity.

Reducing levels of in models can thus be a promising way of enabling more flexible initial consultation to federal state decision makers. Arguably, the obvious challenge in the modelling process is to balance the reduction in the level of detail with the model's explanatory and

[8] For example, the widely used MARKAL model has been applied to the U.S. with over 4000 technologies depicted. [49].

[9] Scenario studies on a federal state scale are noticeably limited in their input data availability, often leading modellers to use value-based assumptions, which have no factual scientific basis [51]. Although German federal states maintain their own respective statistical offices, the data range provided by them does not always match. For example, a recent disaggregation of the car fleet into different technologies is available for the state of Baden-Württemberg [52] but not for Saxony-Anhalt [53].

[10] Assuming a model with a single year of 8760 hourly time steps, 20 technologies, 20 locations and 5 time-dependent constraints (e.g. maximum generation per location), results in more than 17 million constraints. Such models require considerable CPU and memory requirements that can take up to several days or weeks to solve [2,55].

predictive power, which eventually reflects in credibility towards clients [51,56,57]. As mentioned before, novel methodologies may help alleviate this issue by reducing complexity in terms of temporal, technical and spatial modelling detail [2].

(III) Lack of transparency and replicability in scenario studies (“black-box modelling”)

Researchers frequently call for efforts to enhance transparency and comprehensibility in the communication of modelling approaches towards decision makers [18–20,42,45,58]. Even though scenario developers and modellers are usually aware of the complexity and uncertainty inherent in their models, they eventually fail to convey these issues to their target group. As a consequence, decision makers frequently misinterpret scenario projections as actual forecasts which may lead to errors in policy making [20–22,58].

The situation is aggravated by the fact that many models are built as "black boxes" that exclude scenario results from scientific scrutiny and replicability by restricting access to model code and data [12,18,42,58].[11] This gives rise to three concerns [12]: i) hidden flaws or bugs in the source code or data, ii) subjective or value-based assumptions driving the results and iii) the effect of highly sensitive parameters obscured or absent in the published analysis. Likewise, as Pfenninger et al. argue [58], “these black-box simulations cannot be verified, discussed or challenged. This is bad for science, bad for the public and spreads distrust”.

In conclusion, further research, addressed to decision makers in federal states, should be communicated in a way that it is both transparent and replicable. Modelling outcomes and scenarios must be understandable to the respective target groups if they are to contribute to a democratic discussion and decision-making process [18,20,21]. In this regard, research has developed adequate methods of ensuring transparency in model-based scenario studies [19,61,62] that however need further application in research practice.

1.3. Objective of the research

Drawing upon the research gaps identified, the present research attempts to develop a transparent modelling tool suitable for providing initial consultation at a German federal state level with regard to the long-term dynamics between VRE supply and structural changes on the demand-side of the energy system.[12] The modelling tool will be applied in a stylised application

[11] A notable example for proprietary black-box models is PRIMES, that was used for the European Commission's Energy Roadmap 2050 [59], but which is not replicable by third parties. Multiple scientists criticise the model's incomprehensible assumptions, inaccessible model code and enigmatic datasets [12,60].

[12] Arguably, instead of developing a new modelling tool from scratch, freely available and customisable open source models, such as OSeMOSYS or DESSTinEE, could be utilised for analyses on a federal state level. However, research generally agrees that using open-source models for the sake of time and cost savings may

example for one selected German federal state in order to evaluate its performance and the robustness of its outcomes.

The findings of the research will be of interest to energy modellers and consultants seeking to provide short-term results to contractors at a German federal state level. In addition, the scientific field of energy system modelling might benefit from an application and critical discussion of recent methodologies aiming at capturing VRE-related integration challenges at reduced levels of model detail. In accordance with the objective stated, the present research seeks to address the following research question:

To what extent can a modelling tool with reduced levels of detail yield robust results in scenario analyses for investigating the long-term dynamics between VRE supply and structural changes on the demand-side of the energy system *at a German federal state level?*

Accordingly, the remainder of this study is organised as follows. Chapter 2 outlines the properties of variable renewable energies and analyses their associated techno-economic challenges in theoretical terms. Based on this, Chapter 3 specifies the exact features of the modelling tool, describes its computational implementation, and provides a critical reflection on the methods applied. In Chapter 4, the modelling tool is applied in a stylised application example, followed by a critical assessment of the plausibility of its outcomes. Finally, Chapter 5 refers back to the main research question and summarises the conclusions that can be derived from the analysis.

---

eventually turn out counter-productive due to long periods of training and familiarisation needed [12,19,45,63,64].

2. Theoretical background: Integration of VRE in future power systems

The energy system is characterised by complex dynamics. As introduced in Chapter 1, a large scale deployment of variable renewable energy sources in energy systems is associated with multiple challenges, including the need for flexibility and enhanced transmission capacity [31]. Representing these challenges in a modelling tool designed for scenario analyses on a German federal state level requires a solid theoretical foundation on their techno-economic implications. This chapter explains the significance of VRE by first characterising the key properties of VRE in contrast to conventional power generators (Section 2.1). Subsequently, the integration challenges for the energy system associated with these properties are analysed in detail (Section 2.2). The chapter concludes with the statement that the integration challenge of flexibility should receive particular attention in the modelling tool for federal states (Section 2.3).

2.1. Properties of VRE generators

The operation of variable renewable energies is embedded in the general dynamics of the energy system.[13] Its essential sub-systems and elements include energy supply as well as energy demand, with a corresponding range of energy conversion processes [22,67] (FIGURE 2).[14] For conventional fuels in the energy system, such as natural gas or gasoline, supply and demand can be easily decoupled using pipelines and fuel tanks. In contrast, for the generation of electricity, its transmission via large-scale grids, and the final consumption at the end-user need to be maintained in constant balance [46,69].[15]

---

[13] In general terms, a system is defined as an interconnected set of elements that is coherently organised around some purpose [65]. The purpose of the energy system can be formulated as providing a required amount of energy to consumers [66].

[14] The supply sector involves indigenous extraction as well as imports and exports of primary energy carriers, such as coal, natural gas and crude oil. Further conversion of these energy carriers is needed to make them suitable for specific applications. Such conversion processes include power plants, that convert fossil fuels to electricity, and refineries that convert crude oil to petroleum products. The result of these conversion processes is then called secondary energy, of which electricity, heat and gasoline are of major importance for the system [22]. Following transport, storage and distribution, so called final energy is provided to the end user. Here, on the demand side of the energy system, further conversion into useful energy may be needed, for example converting fuel to heat in a boiler. In its ultimate form, this energy can provide a certain service or function for the user, such as lighting, transportation or room temperature adjustment [22,67,68].

[15] If the grid's power frequency varies from its nominal value of 50 Hertz, safe operation and high power quality are at risk. Ultimately, this may entail in loss of system control and unplanned blackouts [66,69–71].

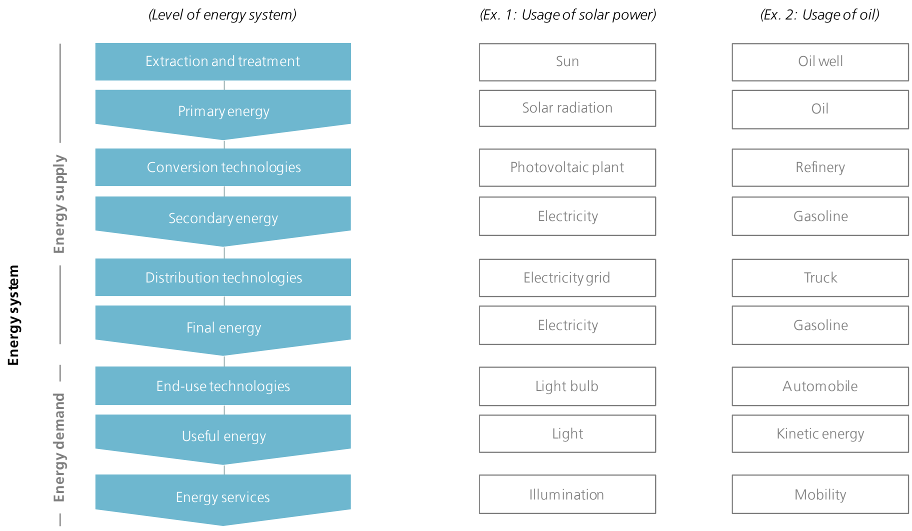


FIGURE 2. Schematic chart of the energy system with two illustrative examples. Ex. 1: a PV plant converting solar radiation into electricity; Ex. 2: crude oil being converted into gasoline to power an automobile. Source: [22].

While conventional thermal power generators, such as gas turbines or coal-fired steam turbines, are designed meet power demand at all times, variable renewable energies have multiple unique properties that complicate power system operation. These properties can be summarised as follows:

a) *Variability:* Due to their weather-dependent nature, VRE generate power in a fluctuating and variable manner [31,33,71]. Generation depends on annual, seasonal, daily and sub-hourly variations in, most notably, wind speeds and solar radiation [21,66]. This results in a limited ability to control VRE output, referred to as a lack of *dispatchability* [2,5].
b) *Uncertainty:* Similar to power demand, VRE generation can be forecast to some extent. Nevertheless, an inherent degree of uncertainty remains in these forecasts. This results in errors in the scheduling process of dispatchable generation technologies [2,72].
c) *Location-constraints:* VRE generators are built in close proximity to major primary energy sources of solar, wind and hydro energy. Conversely, major load centres in Germany are often remotely located from these generators [21,31,66,72].
d) *Distributed generation:* VRE generators increasingly feature as distributed generation via so-called prosumers. By feeding excess electricity from PV installations and other technologies directly in to the distribution grid, the distribution level has to operate in a bi-directional model towards and away from the prosumer [22,70].
e) *Non-synchronous:* VRE resources have a power electronic interface with the grid, rather than a rotating mass that is directly connected [73]. This means that VRE resources cannot generate electrical energy such that the system frequency is in constant ratio and thus in synchronism [2,72,74].

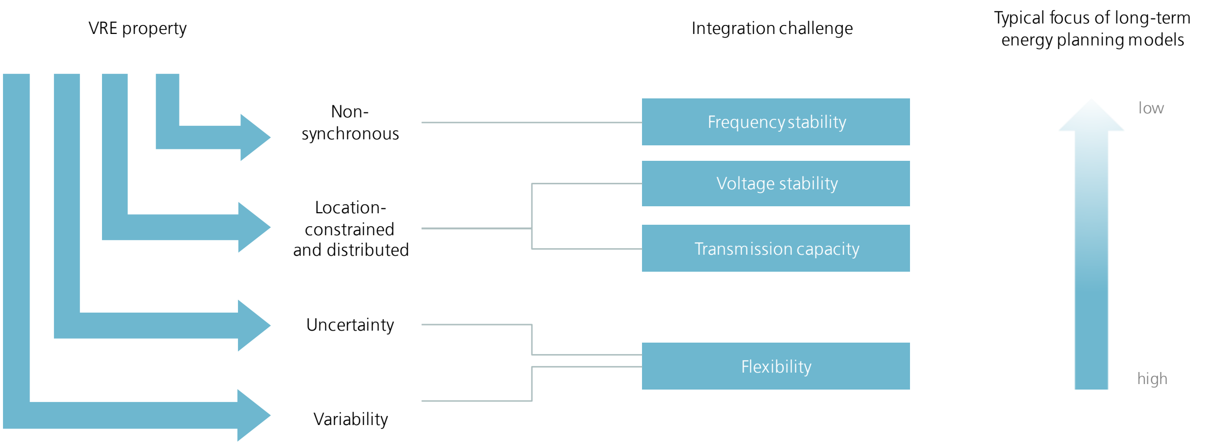


FIGURE 3. Key links between variable renewable energy properties, integration challenges and the typical focus of long-term energy planning models. Source: [2].

The fundamental properties of VRE generators raise the need for certain functional characteristics of the power system – hereinafter referred to as *integration challenges*. FIGURE 3 illustrates the key links between VRE properties, their associated integration challenges as well as the extent to which long-term energy planning models (EPM) typically consider these challenges. As introduced in Chapter 1, EPMs are employed to create scenarios regarding the long-term evolution of the energy system. As such, they typically focus on aspects of technology deployment and system operation that have distinct long-term investment implications [2,3]. The following section describes the integration challenges in more detail and elaborates on their respective investment implications, giving raise to narrowing down the scope of the modelling tool for initial consultation.

2.2. System integration challenges associated with VRE deployment

Based on the properties identified, relevant integration challenges include i) flexibility, ii) transmission capacity, iii) voltage stability, and iv) frequency stability.

i) Flexibility

The integration challenge of flexibility arises from the short-term variability and uncertainty inherent in VRE resources. Power system operators have always been faced with inaccurate forecasts of demand, leaving uncertainty in creating dispatch schedules for supply. Addressing variability in system operation is thus no entirely new phenomenon [2,21]. However, increasing shares of VRE supply imply more rapid, frequent and significant variability in VRE generation. Accordingly, the variability of *residual load* also rises, i.e. the system load minus VRE generation [2,72]. Residual load is either positive or negative. A *positive* residual load means times of VRE deficits whereas a *negative* residual load indicates excess power generation from VRE [75]. As response to this, the non-VRE generators in the power system must match their generation to meet the residual load under different operating conditions at all times in order to ensure generation adequacy, i.e. sufficient generation to meet demand [2]. The underlying assumptions here is that VRE are dispatched first due to their near-zero variable costs as well as VRE priority dispatch regulated by law in Germany [76]. Against this background, flexibility can be defined as the extent to which a power system can adapt electricity generation and consumption as needed to maintain generation adequacy in a cost-effective manner [77].[16] Accordingly flexible adjustments in generation have both technical and economic implications. On the technical side, the issue is closely related to maintaining the power system in a secure and reliable state of balanced voltage and frequency [2,69]. These challenges are elaborated in detail in the sub-section iii) and iv) below. On the economic side, the cost-effectiveness of non-VRE generators is challenged by two interlinked long-term effects.

On the one hand, referred to as the *utilisation effect* [77,78], capital-intensive baseload generators[17] are subject to a reduction in their capacity factors, and thus their cost-effectiveness, as the share of VRE generators increases in the long-term. This effect is illustrated in FIGURE 4 (A) by means of load duration curves.[18] At a VRE share of 17%, baseload operates at least 8000 hours per year (capacity factor of more than 91%), while under a very high VRE share of 70%, baseload has considerably lower full load hours of at least 4500 hours (51% capacity factor). Overall, the precise utilisation effect depends on the mix of VRE deployed, its variability and correlation with electricity demand. In fact, if a well-designed VRE mix with favourable correlation with electricity demand can be deployed, the utilisation effect is of less relevance in economic terms [78].On the other hand, the *balancing effect* refers to additional costs for power plants because they must start and stop production at short notice and ramp quickly in a wide range with to meet residual load in response to increasing VRE shares [78]. This effect is illustrated in FIGURE 4 (B) by means of the hourly ramps (GW/h) of residual load. The graphs show how the operational variability, and thus the balancing requirements, are strongly increased at higher VRE shares [77]. While certain technologies, such as open-cycle gas turbines are designed for these operational conditions, incumbent coal-fired steam turbines may experience significant cost increases due to more frequent start-up and ramping events. When considering both effects together – assuming high VRE shares and that the dispatchable power plant mix needs to be cost-effective – inflexible baseload plant are likely to be replaced by less capital-intensive peaking and mid-merit generation

[16] Definitions of the concept of flexibility vary in scope and detail [75,77]. See [2] for a review of different definitions and the metrics for measurement they entail.

[17] Power plants that are cheapest at a low capacity factor are known as peaking plants. Those that are cheapest in an intermediate range of capacity factor are referred to as mid-merit plants. Finally, plants that are cheapest when running practically all the time are known as baseload plants [78].

[18] A load curation curve is a way to display the electricity demand in a power system over the 8760 hours of one year. For constructing the load duration curve, electricity demand is re-ordered in descending order according to its load level [78].

that is more cost-effective at low capacity factors and less affected by increasing costs for cycling and ramping [77–79].

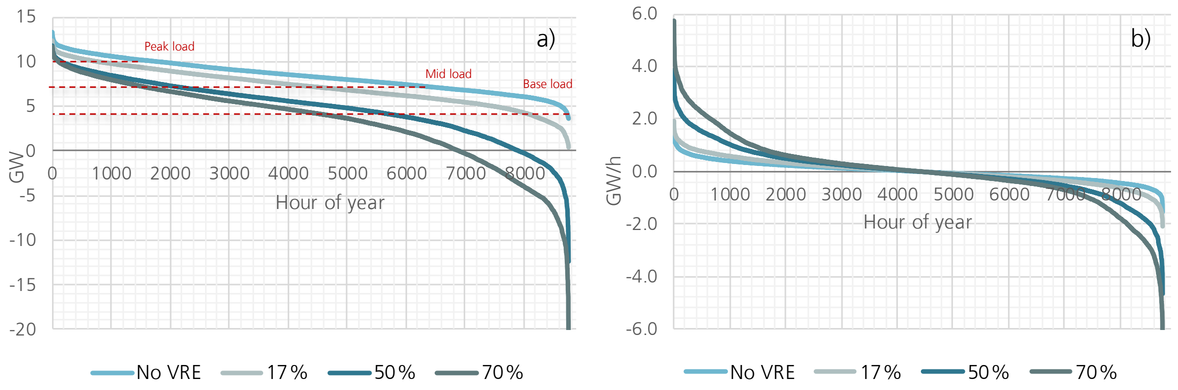


FIGURE 4. Illustrative example of system load (no VRE) and residual load at different VRE penetration levels (share in gross electricity generation). a) Utilisation effect, b) Balancing effect. Load data is for Baden-Württemberg from 2015. VRE (wind and PV) shares are scaled, annual share in 2015 being 17%. Source: author's own, based on [77].

An optimal generation mix is likely to comprise multiple generation technologies, hereinafter referred to as flexibility options. Besides dispatchable power plants, the most commonly discussed flexibility options include storage technologies, demand side management (DSM) and cross-border trade [2,66]. Analytically, these technology options can be divided into three groups [75]:

First, *downward flexibility options* can reduce a positive residual load. Most notably, load shedding applications reduce demand without compensating the reduction at another time. For example, electric arc furnaces in the industry can provide downward flexibility by temporary interrupting electricity provision from the grid and using own electricity generation capacity instead [69,71,75]. Furthermore, thermal power plants, especially highly flexibly gas-fired ones, can adjust their power output and thereby provide downward flexibility [75].

Secondly, *upward flexibility options* help augment the negative residual load in situations with high VRE feed-in and low system demand [75]. Here, two options can be distinguished [75]. On the one hand, curtailment of the feed-in from VRE is possible, meaning that a certain amount of VRE power is not used [5].[19] On the other hand, power-to-X technologies (P2X) can utilise excess electricity for other purposes to avoid curtailment. P2X includes, for instance, conversion of electricity into heat (Power-to-Heat) or into gas (Power-to-Gas) [41,81].

[19] It is a matter of debate in research, whether VRE curtailment may be part of a cost effective solution in power system planning [2]. On the one hand, generating electricity from VRE has nearly zero marginal costs, excessive curtailment may thus signify a badly designed system. On the other hand, additional flexibility options, such as new flexible plants or storage technologies, could require high investment costs only to accommodate a short period of extreme variability. This may be less cost effective than accepting some curtailment [2,80].

Finally, *shifting flexibility options* include technologies used for spatial and temporal shifting. Spatial shifting can be realised through cross-border trade by evacuating VRE when it is being overproduced or by providing access to additional generating resources when VRE availability is low [2]. Temporal shifting uses energy storage devices, such as hydro pumped storage or compressed air storage. These are charged with surplus electricity during times with negative residual load and discharged in times with positive residual load [41,71,75]. The other option for temporal shifting is demand side management (DSM), also referred to as demand response (DR). In DSM strategies, certain electricity consumers, such as households, respond to price incentives by reducing their demand at times of high positive residual load and increasing it in times of surplus electricity production [69,75]. Note that spatial and temporal shifting must provide both upward and downward flexibility. For instance, charging a pumped hydro storage means that it needs to be discharged at a later point because storage capacity is limited [75].

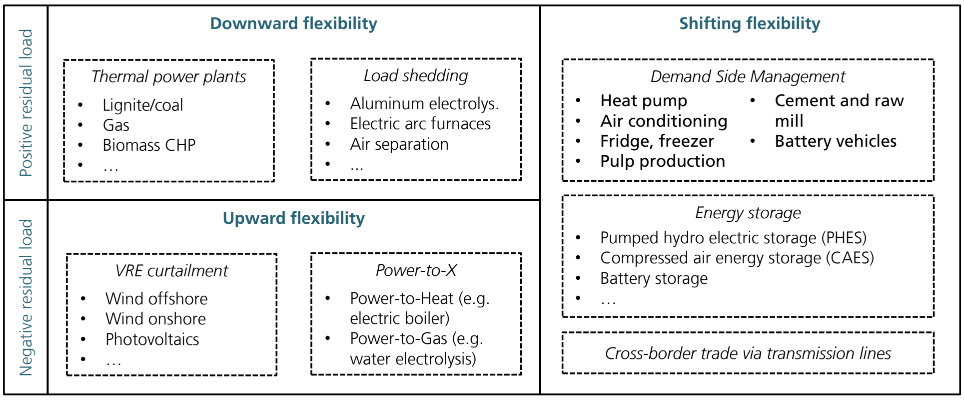


FIGURE 5. Overview of flexibility options categorised by type of flexibility provision. Source: [75].

FIGURE 5 summarises the flexibility options introduced. Clearly, various technologies are likely to compete for flexibility provision in future power systems, given their differences in cost, typical power provided, and the time scales they serve [66,75].

ii) Transmission capacity

The need for adequate transmission capacity arises from the location-specific availability of VRE resources, which is often spatially mismatched with load centres in Germany. Power thus needs to be transported over long distances at high voltage levels [2].[20] In case of inadequate transmission capacity, transmission system operators address transmission bottlenecks by means of VRE curtailment and redispatch actions, which may result in reduced cost-effectiveness of VRE projects

[20] As argued by Pöller [72], especially wind generation is prone to cause grid congestions, which raises the need for additional transmission lines for resolving these congestions. However, due to the variability of wind, additional transmission lines may only be required for a few hours per year and sometimes are not economically feasible. In other cases, bureaucratic procedures for building new lines can take much more time than the installation of wind parks, leading to congestion problems that need to be managed by the transmission system operators [72].

[2,80,82]. As explained in the previous section on flexibility, additional transmission capacity is also relevant with regard to spatial pooling over large geographical areas, which can mitigate much of the weather-related variability of VRE. Research suggests that in a fully renewable EU power system, a well-developed transmission grid can significantly decrease the residual load [75]. In this regard, especially high voltage direct current (HVDC) technology is an attractive technology option by providing long-distance power transmission at low losses [83].

Overall, from an economic point of view, transmission grids are long-lived capital-intensive infrastructure that has been found to be a no-regret option for smoothing variability and thus reducing VRE integration challenges, making it a likely part of cost-optimal climate mitigation scenarios [7]. Despite its low costs compared with the generation part of the energy system, these additional costs should be reflected in scenario-based long-term energy planning [2,7].

iii) Voltage stability

Power systems can be subject to sudden system failures that can cause voltage and, as explained further below, frequency to go beyond these limits, referred to as *contingency events* [2]. Such system failures are driven primarily by factors such as the sudden outage of a large generator, transmission line or sub-station in the power system [2,72]. The ability of the power system to return to a state of normal operation following the imbalances associated with a contingency event is referred to as *stability* [2,72].

Voltage is the parameter in the power system that indicates whether there is a *reactive power* imbalance in an area of a system. [21] With regard to voltage stability, two issues arise from the location-constrained and distributed properties of VRE generators. First, reactive power cannot be transferred over long distances but must be made available locally. However, especially wind farms are often remotely located from load centres. As a consequence, even if wind farms are capable of delivering reactive power, it cannot be made available at the location where it is needed [72]. Second, wind and PV generators, in contrast to conventional power plants, are typically operating on the distribution grid level instead of the overarching transmission grid. This may cause thermal overloading and the violation of voltage limit [2,72].[22] Both issues can typically be mitigated at moderate cost by installing additional reactive power compensation assets, either based on

[21] In simple terms, *active power* can be thought as power that is actually consumed and is balanced at a system level. *Reactive power* refers to power that assists in the delivery of active power and is balanced locally [2]. ENTSO-E [74] defines active power as "the real component of the Apparent Power at fundamental frequency, expressed in watts or multiples thereof (e.g. kilowatts (kW) or megawatts (MW))" while reactive power is referred to as "the imaginary component of the Apparent Power at fundamental frequency, usually expressed in kilovar (kvar) or megavar (Mvar)".

[22] In Germany this issue is partly compensated by the fact that electricity generated by rooftop PV is remunerated by a net-metering scheme. This makes the self-consumption of generated PV electricity by far more profitable than energy delivery to the grid [72].

switched capacitor banks or static var compensators [2,72]. Dynamic simulations looking at short-term voltage stability can be used to identify the required dynamic performance of additionally required reactive power assets [72]. Consequently, according to IRENA [2] the investment required for voltage control is moderate and of low relevance for long-term transition planning.

v) Frequency stability

Besides voltage, power system operators need to maintain system frequency within acceptable limits. *Frequency* is the parameter of a power system that indicates whether there is an imbalance between active power generation and consumption [72]. Following a contingency event, frequency imbalances can occur within different time scales, ranging from a few seconds to several minutes [72]. These imbalances are addressed by activating *active power reserves*, which are traded as ancillary services in the liberalised German electricity market [72,83]. Immediately after the power balance is disturbed, synchronous connected generators release or absorb kinetic energy in or from the grid to counteract the frequency deviation within a few seconds. This process is referred to as *inertial response* or simply *inertia* [84].[23] If the frequency deviation surpasses a specific value following a contingency event, the *primary reserve* is activated which returns the frequency to save values within 30 seconds by increasing or reducing generation. Subsequently, the *secondary reserve* is activated to return the system frequency to its nominal value within several minutes. Finally, the remaining frequency deviation activates the *tertiary reserve,* also referred to as *minute reserve* or *load-following reserve*. Unlike the first two reserve controllers, it requires manual adjusting in the dispatch of generators or changes in the schedule periods [73,84]. FIGURE 6 provides a schematic representation of the frequency response process while TABLE 1 summarises the different levels of active power reserve and indicates the respective capacity of balancing power in Germany in 2014.

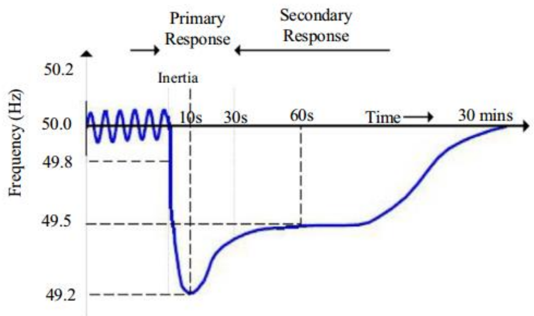


FIGURE 6. Time scales involved in system frequency response. Source: [73]

Power reserve level	Time scale	Capacity in Germany
Inertial response	<10 sec.	-
Primary response	10-30 sec.	± 568 MW
Secondary reserve	5-15 min.	± 1900 MW
Tertiary reserve	15-60 min.	± 2400 MW

TABLE 1. Characterisation of active power reserves in Germany. Source: [72,83,84]

[23] Synchronous generators are characterised by rotating masses that inject or absorb kinetic energy into or from the grid in case of frequency deviations [2,72]. This provides inertia to the system, defined as the "resistance of a physical object to change in its state of motion, including changes in its speed and direction" [84].

Large-scale deployment of VRE does not necessarily influence the occurrence of contingency events, yet it changes the system's ability to respond to contingency-driven imbalances in frequency [2]. With regard to inertial response, the rotating masses of synchronous generators normally determine the immediate response to frequency imbalances [84]. However, as explained above, VRE generators generally are non-synchronous – integrating more VRE into the power system will thus reduce the number of conventional generation units providing inertial response. As a consequence, the lower system inertia, the less damping is provided to the system and the more nervous the grid frequency reacts to abrupt changes in generation and load patterns [73,84]. This may require investments in operational equipment of VRE generators to support frequency response, an adaptation referred to as synthetic or artificial inertia [2,72].[24]

Regarding primary and secondary reserves, research expects a negligible impact of VRE generation on additional reserve capacity required. This is because, in the short term (time frame <15 minutes), the total amount of wind and solar generation is relatively constant while the amount of required reserve mainly depends on worst case assumptions with regard to large, unplanned power plant outages [2,72]. However, referring back to the issue of flexibility, VRE have considerable impact on the amount of tertiary reserve power needed because of the variability and the limited predictability of wind speed and solar irradiation. Overall, having introduced the four major integration challenges associated with VRE deployment, the following section concludes on the insights gained.

2.3. Conclusion: Priorities of the modelling tool

This chapter has shown that variable renewable energies have distinct properties that result in multiple techno-economic challenges for long-term power system operation. Ideally, a modelling tool designed for providing initial consultation to German federal state should provide scenarios addressing how to meet needs for flexibility, transmission capacity, voltage- and frequency stability under growing VRE shares and different conditions on the demand side. Insufficient planning by negligence of these challenges could result in a substantial misallocation of capital and in a sub-optimal mix of power generation capacity [2]. However, considering the limited time resources available for the present study, limiting the modelling tool to certain aspects of the complex dynamics of VRE-related integration challenges is inevitable.

By recapping the long-term investment implications associated with the integration challenges, priorities for the model development can be set. First, the issue of flexibility is associated with long-lived capital assets, including power plants, storage facilities and other flexibility options. The question of how to provide a cost-effective generation portfolio should thus receive high priority

[24] See Dreidy et al. [73] for a comprehensive review of the techno-economic aspects of inertia and frequency regulation controllers for wind turbines and photovoltaic plants.

in the modelling tool. Second, given its lower cost implications, assessing needs for transmission infrastructure is commonly referred to as a subsequent step after having defined generation capacities [2,7]. Its priority is thus secondary with regard to initial consultation. Finally, a low priority for long-term planning at a federal state level can be attached to the issues of voltage and frequency control. While the former challenge is likely to require reactive power compensation assets at high VRE shares [72], the latter is associated with a need for synthetic inertia provided by VRE generators [73,84]. However, as research suggests, the long-term investment implications of such operational adjustments are likely to be marginal when compared to the overall investment needs for power generation [2,72].

In conclusion, the modelling tool envisaged for initial consultation on VRE-related system impacts on a German federal state level will put particular emphasis on the issue of flexibility, i.e. the question of what generation mix can cover power demand in a cost-effective manner. In this regard, the following chapter elaborates on the development of the FederalPlan tool.

3. Methodology: Development of a modelling tool for initial consultation

As the previous chapter has shown, the integration challenges associated with the deployment of variable renewable energies (VRE) are a complex matter that required further delineation of the research. As a result, the future need for flexibility options in response to VRE deployment is defined as the focus of the modelling tool, whilst accounting for essential demand side dynamics of the energy system. In order to make the modelling tool suitable for providing initial consultation to federal state decision-makers, Section 3.1 elaborates and discusses how data and computational needs in long-term energy planning models can be kept manageable by reducing levels of temporal, technical and spatial detail. Based on this analysis, Section 3.2 outlines the major features of the novel modelling tool 'FederalPlan'. Section 3.3 specifies these features with regard to the demand side of the energy system and discusses alternative modelling approaches, while Section 3.4 accounts for the supply side. Section 3.5 provides a critical qualitative reflection on the modelling approach selected, highlighting possible improvements. Finally, Section 3.6 concludes this chapter with a brief review of the qualities and limitations of the FederalPlan tool.

3.1. Reducing levels of detail in a modelling tool designed for initial consultation

As introduced in Chapter 1, a long-term energy planning model, designed particularly for providing initial consultation to federal states, should be characterised by two essential aspects:

- Data needs should be minimised in order to reduce the time needed for model calibration and parametrisation in federal state scenario analyses.
- Computational complexity should be reduced in order to avoid lengthy running times for single model runs.

This can be achieved by making well-reflected simplifications in terms of temporal, technical and spatial detail with regard to the techno-economic challenges related to VRE and the need for flexibility. Research generally concludes that low levels of detail either over- or underestimate VRE deployment and associated integration challenges [2,3]. A critical discussions of the simplifications made is thus an integral part of the following section.

Temporal detail

Temporal detail has two essential dimensions. The first can be referred to as the *time steps* and is used to describe the development of capital stocks and investment decisions. Typical EPMs apply time steps of about 5 years. However, in order to limit computational complexity, the modelling tool to be developed is set to model a single target year. The second dimension, referred to as the *temporal resolution*, aims at representing the operation of the power system, accounting for the short-term variability of both VRE supply and load, as well as the resulting flexibility requirements [2]. There is a recent wealth of work using various methods to reduce the temporal resolution in EPMs for the sake of improving computational performance [3,55]. Four broad categories can be distinguished, summarised in TABLE 2 and characterised below in ascending order of temporal detail.

A first method aggregates demand in a load duration curve (LDC) (see Section 2.2), divides this curve into 5 to 10 sections, and matches electricity demand with available supply options. This approach is also known as the integral method [31]. Each time slice then represents an average of the power demanded in a fraction of the year, as well as an average of the available generation from VRE. While the advantage of this method is its simplicity and the low data requirements, its major disadvantage is that it does not take account of real-time dynamics and chronology of demand and supply that are lost due to the time and power aggregation to building the LDCs. VRE generators thus completely lose their intrinsic power variations to a constant capacity factor and the value of storage systems and other load shifting options cannot be assessed [3,5,31,85].

A second method consists in dividing the year into a set of 10 to 100 time slices that capture average seasonal, weekly and daily power variations, sometimes referred to as the semi-dynamic method [2,31]. Similar to the previous approach, the method does not retain chronology and thereby implies considerable limitations in assessing flexibility options.

A third method refrains averaging data for the creation of time slices, but instead uses different approaches to create so-called typical days of similar load, wind speed, solar irradiance patterns. Specific approaches range from simple heuristics, to statistical clustering algorithms (including k-medoids, k-means, and fuzzy C-means) and advanced optimisation models [3,55,86]. While chronology can be retained in some of these approaches [3,55] there are well-known disadvantages. Specific algorithms or optimisation models need to be set up, calibrated and validated in terms of their statistical significance – a time-consuming process requiring far more effort than the previous methods [85]. In addition, specific approaches for creating typical days are found to vary in performance and strongly depend on the structure of the underlying model [55].

Finally, the method with the highest degree of temporal detail consists in using the full extent of load and VRE generation time series under its native resolution (hourly or better), also known as the *dynamic method* [31]. In a next step, each hourly demand step needs to be matched with the available supply, according to a predefined dispatch rule. The main disadvantages of the approach are its large data needs and, compared to the other three approaches, its relatively long computation time. In turn, it offers a high level of detail with regard to supply and demand dynamics occurring throughout the year [31,55].

TABLE 2. Main approaches to reduce temporal detail in energy system models with an indication of the order of magnitude of resolution in time. LDCs = load duration curves. Source: [55].

	Time steps	Time resolution	Temporal correlation	Example
Average availabilities/LDCs	1-10	Monthly-yearly	No	LEAP
Time slices	10-100	Hourly-daily	No	TIMES
Typical days or weeks	100-1000	Hourly	Method-dependent	LIMES-EU
Full time series	>1000	Hourly and better	Yes	HOMER

Overall, reducing the temporal resolution in a model leads to a disregard in terms of variations and correlations in power demand and VRE supply, continuity, as well as the time-linked operational constraints of the power system with regard to flexibility [2]. More specifically, different authors have investigated the impact of the temporal resolution on investment decisions in the power system. Poncolet et al. [85] find that with a lower temporal resolution, the optimal level of investments in less flexible baseload technologies is overestimated, while investments in flexible dispatchable generation is underestimated. As a result, stylised temporal representations will lead to an underestimation of the total system cost with growing VRE shares [3,85]. Haydt et al. [31] compare the performance of the LDC approach, time slices and full times series using a case study and different scenarios. They state that the use of renewable energies can be seriously overestimated if possible mismatches between supply and demand are not analysed properly.[25] For long-term planning this means that there could be sub-optimal investments into new generation capacity, underestimation of CO_2 emissions and overestimations of renewable shares in the electricity mix [31]. With regard to computational performance, Kotzur et al. [86] compare different aggregation methods for the creation of representative days. Results indicate that these methods can well represent time series of solar irradiation, temperature and electricity load with a small error, while significantly reducing computational time.[26]

In conclusion, temporal detail is an important lever for model results. For the present research, the first two approaches introduced seem unsuitable due to their high degree of aggregation and loss of chronology. Using the method of representative days appears promising in terms of computational performance and accuracy, yet its implementation is time-intensive and requires expertise in selecting appropriate selection algorithms. The modelling tool in the present study will thus employ a non-aggregated hourly resolution. This is in line with multiple authors who

[25] In a case study for the island of Flores (Portugal) applying a scenario with high VRE shares, the LDC method does not capture any VRE curtailment at all (0.00% of total VRE electricity generated). Time slices represent some curtailment (2.06%), which is even greater when using the full time series (9.08%).

[26] For instance, a total of eight to twelve representative days (using clustering algorithms) was sufficient to reach cost prediction errors less than 2% while reducing the solving duration of the optimisation problem by a factor of 50 in comparison to using the series of a full year [86].

recommend hour-by-hour resolutions for adequately capturing the variations in power demand and supply [31,33,55].

Technical detail

Technical detail refers to two aspects: one the hand it means the overall coverage of generation technologies in a given model, i.e. the *technology portfolio*. In order to provide meaningful insights to federal state decision makers, the modelling tool will feature a comprehensive portfolio, including power plants, cogeneration plants, storage facilities, DSM, as well as power-to-heat and power-to-heat applications. On the other hand it signifies to what extent a model accounts for operational constraints of generation technologies and the costs associated [85].[27] In reality, power plants and storage facilities are subject to a range of operational restrictions: ramp rates (the rate at which a generator can change its output), start-up times (the time required for power to start up), minimum load levels (the minimum at which the power plant can be operated stably before it needs to be shut down), minimum down times (the lower limit of the time that a plant needs to be offline), and partial load efficiencies (the reduced efficiency of a power plant operated below its rated capacity) [2,78].

As introduced in Chapter 1, long-term energy planning models (EPM) are designed to examine the dynamics of the energy system in its entirety. Retaining computational tractability with this model type requires simplifications on a technical level, which contrast with the operational detail of dedicated production cost models (PCM), also referred to as dispatch models or unit commitment models [2,3]. While PCMs often rely on mixed-integer linear programming techniques to account for the operational constraints of power generators on a plant-by-plant level, EPMs typically consider a technology-type level without representing dedicated operational constraints [85]. However, research has developed parametrisations for EPMs that aim to mimic flexibility requirements imposed by increasing VRE shares in power system in a rather stylised way [87].

A first category of such parametrisations involves economic penalties in the form of increased operation and maintenance costs for generation technologies, reflecting the increased wear and tear from fast ramping of units, and from starting and stopping units more frequently. The underlying assumption is that power plants are fully flexible at a given point in time [2,85]. Examples for these approaches include [5] and [46]. The effect of this parametrisation at high VRE shares and a high degree of variable residual load is that less flexible power plants will be affected in terms of their overall cost-effectiveness, resulting in reduced deployment of such technologies compared to a case where these additional costs are neglected.

[27] Technical detail is linked to the temporal resolution, e.g. when modelling detailed load-following constraints such as ramping rate restrictions, this requires chronological data at a sufficiently high resolution [3].

A second category attempts to bridge the gap between EPMs and PCMs by introducing operational constraints in long-term planning models. For example, Welsch et al. [32] define ramping requirements in the OSeMOSYS model, which can be met by a combination of thermal generation technologies, each with unique ramping capabilities. In addition, the model incorporates minimum stable generation levels, limiting cycling of generation technologies between that level and their maximum capacity [2]. Ueckerdt et al. [87] equip the REMIND model with so-called flexibility coefficients. These are attributed to each generating technology representing the fraction of its generation that is considered to be flexible (if positive) and the additional flexible generation that would be required for each unit of the technology's generation (if negative). The coefficients are used in a flexibility constraint, which demands flexibility requirements associated with load and VRE generation are met by flexibility provided by other generation technologies [2]. A limitation of this approach is that the flexibility elements introduced rely on exogenous parameters that are difficult to parameterise in a rigorous way. Hence, the validity of these approaches cannot always be guaranteed [3,87]. In addition, these approaches may involve equations of higher order, resulting in increased numerical complexity.

For the present study it appears sufficient to rely on the first category of approaches for multiple reasons. First, accounting for the load and VRE variability in an hourly temporal resolution already incentivises investments in more flexible thermal plants. The reduced utilisation of these power plants induces a shift towards less capital-intensive intermediate and peak load power plants, which are more flexible than base-load plants [87] (see Section 2.2). Furthermore, multiple studies suggest that the costs for providing sufficient flexibility with increasing VRE shares are low, i.e. less than 6 EUR per MWh of VRE, even at high VRE shares [78,87,88]. In addition, must-run constraints of power plants might strongly decrease because of technological advances and retrofitting of incumbent units [79,87]. In conclusion, the modelling tool will focus on a broad technology portfolio and account for additional operational costs, while technical flexibility restrictions are generally not accounted for.

Spatial detail

With regard to flexibility needs on a federal state level, spatial detail essentially refers to two aspects – the definition of *system boundaries* as well as the *spatial resolution* of VRE generators. Considering system boundaries, federal states are no isolated entities but rather integrated in the overall German power system and associated markets. Accordingly, cross-border trade among federal states as well as surrounding countries enables evacuating VRE when it is being overproduced as well as using additional generating resources when VRE availability is low, which is an important flexibility option (Chapter 2.2) [2,71,81]. Performing scenario analyses for single federal state necessitates the delimitation of analytical system boundaries by defining the number and extent of internal and external regions [89].[28]

A first category of federal state scenario studies defines several internal regions (also referred to as nodes), with each of these being characterised by distributions of load, VRE generators, and non-VRE generators [90,91]. Investments and trade between these nodes can then be determined to maximise benefits from the differences in the nodes' costs in generating electricity at any time [2]. The major difficulty about this approach is to populate several internal regions with adequate input data [41]. Moreover, the approach entails a high degree of computational complexity due to the endogenous calculations performed across several regions.

A second category of studies simplifies these dynamics by understanding the single federal state under consideration as the only internal region, see for instance [35,38,92]. Power generation and demand thus need to be balanced within the federal state, with the option to represent imports and exports via exogenous parameters. While this approach is not only more practical in terms of data and computational needs, it is also of political relevance as some federal states mention security of supply and a focus on domestic generation as a key priority in their long-term energy system planning [93]. However, given the exogenously defined power transfers in this approach, it risks over- or underestimating the system needs for power generation and flexibility options within the federal state (internal region) under consideration [78]. Nonetheless, the approach seems appropriate for the present study, given its low computational complexity and data needs in designing scenarios.

The spatial resolution refers to the extent to which the model takes the heterogeneous regional generation from VRE into account, including capacity factors and the matching with system load in different locations [7]. Some scenario studies use generic profiles for system load as well as for generation from wind power and photovoltaics [92]. A more detailed approach consists of using geographic information system (GIS) data to derive characteristic wind and solar irradiation patterns for a given federal state. Considering the availability of open-source GIS platforms for these purposes [94,94,94], this approach seems feasible for the present research.

[28] Internal regions are simulated endogenously in the model, and there are cross-border commodity flows where appropriate. External regions are outside of the model boundary and provide only power imports and exports to the internal region [89].

TABLE 3. Overview of planned detail reductions in the design of a modelling tool for initial consultation. Source: author's own.

	Properties selected for the modelling tool
Temporal detail	
Temporal resolution	- hourly: non-aggregated time series for power generation and system load
Time intervals	- single target year
Technical detail	
Technological portfolio	- extensive: take account of wide range of flexibility options (power plants, storage, DSM, P2H, ...)
Operational constraints	- limited: mimic constraints by using economic parameters
Spatial detail	
System boundaries	- single internal region: balance generation and load within federal state boundaries; exogenous imports/exports with surrounding regions
Spatial resolution (VRE)	- high: use GIS data to derive VRE generation patterns for region under consideration

TABLE 3 provides an overview of the planned detail reductions set out in this chapter with regard to the modelling tool to be developed. Concluding this section, there are numerous methodological approaches to reduce the levels of temporal, technical and spatial detail in long-term energy planning models for the sake of lower data needs and computational complexity. Based on the priorities set, the following section specifies the features of the FederalPlan model.

3.2. Model characterisation and features

After having discussed the general options for making a modelling tool appropriate for providing initial consultation to federal state decision makers, this section specifies the key features of the newly developed modelling tool FederalPlan, which are illustrated in

FIGURE 7. As described in the previous chapters, future power system configurations along with the need for flexibility options do not solely depend on the deployment of variable renewable energies, but likewise on the anticipated evolution of energy demand and its conceivable structural changes. Approaching scenario studies from the power supply side only thus risks excluding essential dynamics within the entire energy system, which may lead to misinterpretations and selective policy interventions [18,23,49,64].

Accordingly, an essential feature of the FederalPlan tool is the projection of future energy and power demand in the different demand sectors, including options for fuel and technology substitution towards electrification, improvements in energy efficiency, and socio-economic impacts. These stylised demand projections are used as input for two sub-features of the model. On the one hand, the model provides endogenous modelling of future electrical load curves. This takes account of the fact that shape of the load curve is likely to change in response to structural changes, which, in turn, may have system-wide implications, such as a greater need for managing load peaks and troughs through flexibility options [95]. On the other hand, the model performs an endogenous assessment of potentials for demand side management (DSM). These potentials can be attributed to scenario-specific diffusion of appliances and processes in the residential, industry, and tertiary sectors. They are utilised at the power supply stage of the model to shift demand across between time steps.

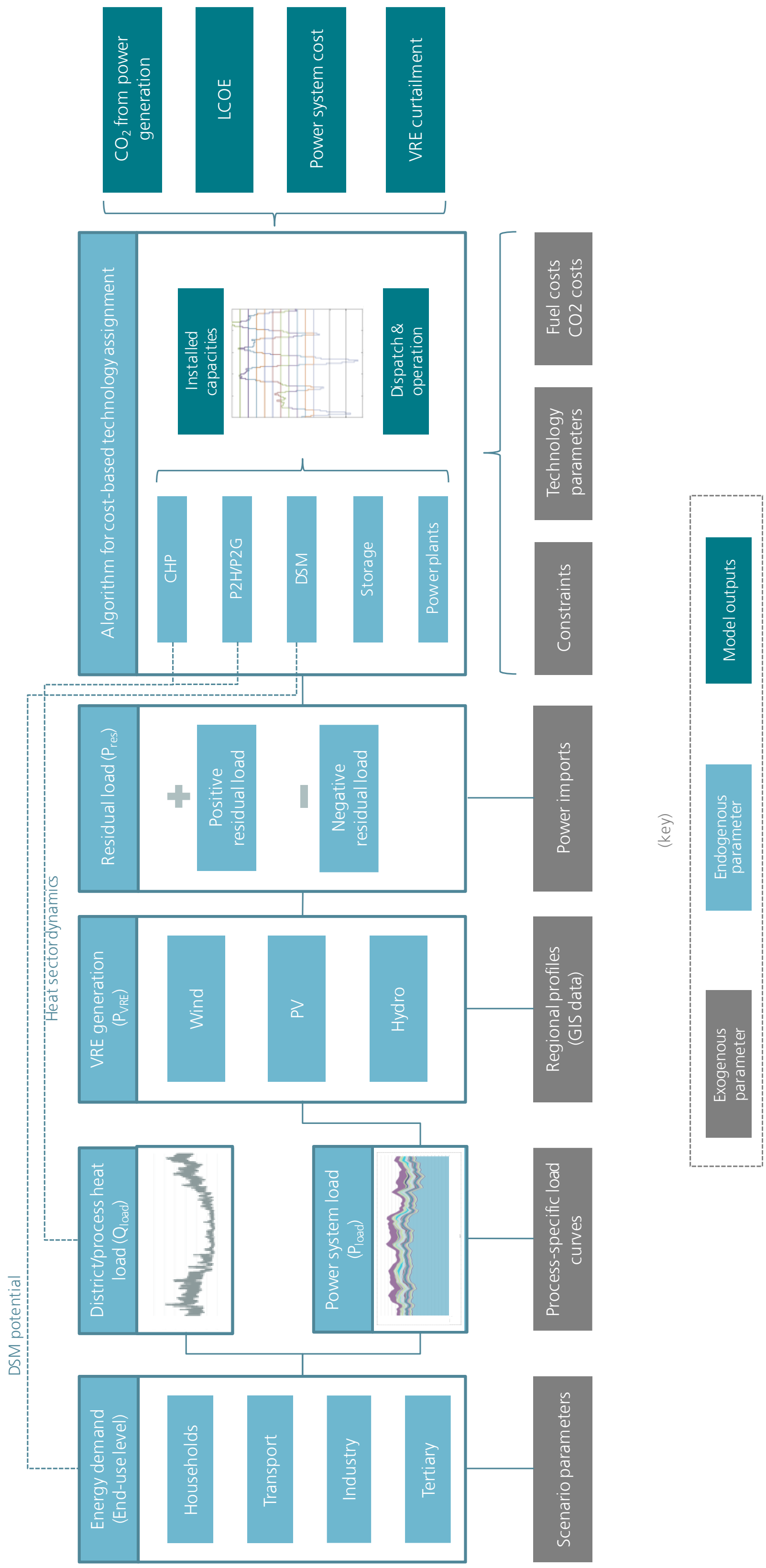


FIGURE 7. Conceptual model of the major dynamics in the FederalPlan tool. Source: author's own.

The centrepiece of the model's supply side is the algorithm for cost-based technology assignment. This algorithm performs a reduced-form, cost-based optimisation of power supply system configurations. More specifically, it simultaneously optimises both investments into power plants and flexibility options, as well as their dispatch with hourly resolution over the full 8760 hours of a year in order to minimise total system costs. These costs, expressed by the levelised cost of electricity (LCOE), represent the sum of annuities of installed capacities, variable fuel and CO_2 emission costs, fixed operation and maintenance costs, as well as ramping costs for power plant start-ups. Constraints include the balance of power supply and demand at every hourly time step, as well as exogenous settings, such as limits for installed capacities of certain technologies. Decisions are made from the perspective of a central planner with perfect information, with costs following a socioeconomic least-cost strategy without consideration of business-economic market strategies [33,96]. Overall, one run of the model algorithm results in the structure of the supply system with minimised costs at given parameters and constraints for a single target year.

According to the components depicted in

FIGURE 7, the model is transformed into computer code. Options include programming languages, such as C++, Java and Python, or simulation languages, as for instance MATLAB, NetLogo, Excel and Stella. Excel appears suitable for the given research, considering its low entry barriers, extensive functionality, transparency in reflecting relations between parameters and possibility for automation through VBA coding (Visual Basic for Applications) [64]. Moreover, existing modelling tools such as DESTinEE [97], STREAM [98] and MAED [99] demonstrate the software's applicability for simplified modelling.

3.3. Demand side implementation

Energy and power demand in different sectors and end-uses of German federal states are likely to experience considerable structural changes over the upcoming decades. Accordingly, the demand module of the FederalPlan tool enables detailed projections with regard to future energy demand (Section 3.3.1). Subsequently, the method for endogenous power load modelling is introduced and discussed (Section 3.3.2). Finally, the approach for assessing demand-side management potentials in the demand sectors is described (Section 3.3.3).

3.3.1. Sectoral energy demand

Having estimates of future energy demand is a critical element of long-term energy planning. The purpose of the sectoral energy demand module is to provide the possibility to explore a variety of technologies in the different energy-consuming sectors, such as the diffusion of heat pumps or electric vehicles. These projections are then used in the supply side of the model to investigate robust investment plans and different power system configurations. For this purpose, two fundamental and contrasting approaches to demand projections for energy can be distinguished:

top-down modelling (also referred to as the econometric approach), as well as bottom-up modelling (also known the process approach) [68,100].[29]

The top-down approach to demand projection consists of correlating past energy demand for a given fuel with other variables – such as fuel prices, prices of substitutes, income, and other factors – by means of detailed regression analyses of past data [102]. Future energy demands for specific fuels are then related to the predicted growth of these variables, reflected in an overall demand function [17,42,100]. An advantage of the top-down approach is that the approach can take a number of important demand-determining variables explicitly into account [100]. On the downside, the top-down approach has no explicit representation of technologies and thereby cannot reflect technological change and saturation processes, which are particularly relevant with regard to long-term projections in German federal states [20,26,42,100,103]. In addition, the approach has flaws with regard to determining reliable values of income and price elasticities [104].

The bottom-up or process modelling approach to demand projection shifts the estimation process away from fuel consumption itself to an understanding and quantification of the technologies that consume energy. Its underlying idea is that final energy is only an intermediary good, which is used by energy-converting devices and appliances to provide useful energy and, eventually, a particular energy service (see also Figure 2) [68,100,105]. Hence, a key feature of the bottom-up approach is its disaggregation of final energy demand into different end-use categories, such as space heating or lighting. In a next step, the amount of useful energy can be determined by multiplying the rate of energy use with that sued by a particular appliance [41]. With regard to scenario analyses, exogenous drivers and structure parameters can be linked to each of these levels, yielding a detailed image of future energy demand.

Considering its mathematical logic, the bottom-up approach is commonly divided into three types [7,20,21,106]. In brief, *optimisation* models follow a normative logic by defining an optimal set of technology choices to achieve a specific target at minimised costs under certain constraints [48,103]. *Simulation* models aim to predict the behaviour of energy-consuming decision makers by applying a high degree of endogenous parametrisations [25,48,103]. Finally, the *accounting* type of bottom-up modelling does not simulate or optimise technology choices and market behaviour, but leaves these dynamics up to the modeller, based on exogenous input parameters [67,101,103]. Given the main purpose of the demand module in the FederalPlan model, a simplified accounting framework appears sufficient to analyse different configurations on the demand side and their

[29] Besides these two major approaches, there has been an increasing number of hybrid models that aim at combining the advantages of both perspectives. Given their typically high complexity with regard to projections of energy demand, they are neglected in the present research. See for instance [20,27,101] for comprehensive discussions of hybrid model properties.

system-wide implications. As such, the major advantage of the bottom-up approach is that it incorporates a high degree of technological detail and thereby gives a detailed picture of energy demand technologies and plausible technology futures [20]. In addition, the approach is useful for modelling technology regulation policies due to its technical depth [100,107]. In turn, a disadvantage of the approach is its need for disaggregated data to describe energy end-uses and technological options in detail [23,107]. However, this problem can be attenuated by building upon data available for the whole of Germany, if necessary.

Considering these qualities, an accounting-based bottom-up approach appears most useful for the objective stated. The starting point for this approach is the energy balance for the federal state under consideration. These are available from [108] for the period from 1990 to 2015. Based on this, the implementation of the approach in the four final energy sectors laid out in the energy balances – households, transportation, industry, trade and commerce – is set out in the following sub-sections.

i) Households

Providing a detailed image of energy demand patterns in the residential sector on a German federal level requires a disaggregation of final energy demand into different end-use categories. However, single federal states have not yet developed own end-use balances. Therefore, the FederalPlan model integrates the end-use balance developed for Germany in 2015 [109], with the underlying assumption being that the demand structure is similar at a level of single federal states for the same base year. Having a closer look at this disaggregation in FIGURE 8 A), about 68.5% of final consumption in Germany in 2015 is used for space heating, followed by hot water preparation and process heating. FIGURE 8 B) reveals that electricity is the only fuel used for end-uses such as refrigeration and air conditioning. While its share in space heating is only about 2.1% in 2015, this value is likely experience a strong increase in future decades, given the increasing diffusion of heat pumps and direct electric heating [9].

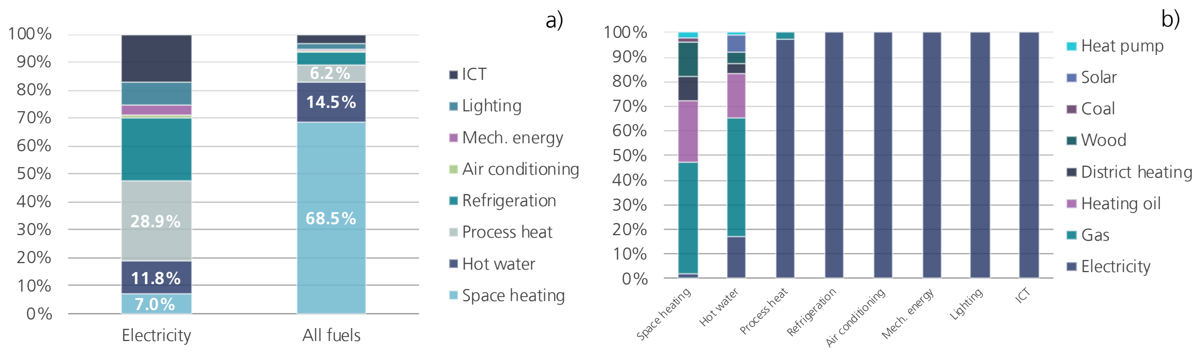


FIGURE 8. End-use balance for the household sector in Germany in 2015. Shares in final energy consumption. a) Electricity and total fuels divided by end use. b) End-uses divided by fuel. Source: author's own, based on [109].

The main scenario driver for the residential sector is set to population growth. Structure parameters are cohabitation (residents per dwelling) and average dwelling size (m² per dwelling). Corresponding demographic data are available from the websites of the federal state statistical offices (e.g. [52] for the case of Baden-Württemberg). Useful energy demand is estimated for the end-uses space heating and hot water preparation. For space heating the model calculates the specific useful heat demand (kWh/m^2) to mimic average improvements in building's thermal insulation performance for the target year. For this purpose, it is assumed that each energy carriers listed in the end-use balance [109] represents a particular heating supply technology. This results in a total of eight technologies, including electric heat pumps and solar thermal collectors (TABLE 4). Conversion efficiencies for these technologies were derived from the Energy Transition Model [110]. These are listed in Appendix 7.2. Note that due to data limitations at a federal state level, the model includes no disaggregation of the building stock into different age classes and building types.[30] A similar approach is taken for hot water preparation, with each fuel in the end-use balance representing one supply technology.

TABLE 4. Household end-use categories and technology options in the FederalPlan model. Source: author's own.

End-use category	Technologies			
Space heating	Coal-fired heater Condensing gas boiler	District heating Electric heater	Electric heat pump Oil-fired heater	Solar thermal collector Wood pellet stove
Hot water	Coal-fired boiler Condensing gas boiler	District heating Electric boiler	Electric heat pump Oil-fired boiler	Solar thermal collector Wood pellet boiler
Process heat	Electric stove Gas stove	Induction stove Dish washer	Tumble dryer	Washing machine
Refrigeration	Fridge	Freezer		
Air conditioning	aggregated: kWh/resident			
Mech. Energy	aggregated: kWh/resident			
Lighting	aggregated: kWh/m²			
ICT	aggregated: kWh/resident			

Process heat is used in cooking appliances and stoves, as well as partly in some white appliances. To simplify matters, it is assumed that 75% of the energy consumed by dish washers, tumble dryers and washing machines can be allocated to process heat, while the remaining 25% are allocated to mechanical energy (for tumble dryers and washing machines) or ICT (dish washers). Germany-wide average equipment rates for white appliances are taken from [111], full load hours to estimate annual energy consumption are derived from [112]. Energy demand in the remaining end-use categories is expressed as a function of the number of residents ($kWh/resident$) or of the total household area (kWh/m^2).

[30] Future versions of the model could include more detailed estimations of useful heat demand by accounting for insulation and ventilation characteristics of homes and buildings, the volume to be heated, free heat generated by occupants and the sun, as well as heat losses of electrical appliances [67].

ii) Transportation

Energy demand in the transport sector is generally characterised by passenger transport and freight transport purposes [67]. Transport activities in passenger transport are normally measured by the indicator of passenger kilometres $(p * km)$, which is derived from the number of passengers transported multiplied by the distance travelled. Tonne kilometres $(t * km)$ are an indicator for freight transport, reflecting the product of freight transported and the transport distance [67,113].

In the FederalPlan model, the level of passenger traffic (in pkm) in the target year is determined by the driver parameter population (in $inhabitants$) and the structure parameter mobility (in $pkm/inhabitant$). Freight transport activity (in tkm) is driven by GDP (in €) and the transport intensity (in $tkm/€$). Both categories are further disaggregated according to the modal split. Each transport mode is then characterised by different technologies with individual conversion efficiencies (pkm/MJ and tkm/MJ, respectively). These efficiencies are derived from the TREMOD model [114] as well as the Energy Transition Model [110]. Table 5 provides an overview of the technologies included in the FederalPlan model. A more elaborate overview of technology-specific efficiencies is provided in Appendix 7.2.

Table 5. Transport categories, modal split and technologies in the FederalPlan model. CNG = compressed natural gas; LPG = liquefied petroleum gas; LNG = liquefied natural gas. Source: author's own.

Category	Modal split	Technologies		
Passenger transport	Cars	CNG Diesel	Electricity Hydrogen	LPG Gasoline
	Trains	Diesel	Electricity	Coal
	Trams/metros	Electricity		
	Busses	CNG Diesel	Electricity Hydrogen	LNG Gasoline
	Motorcycles	Electricity	Gasoline	
	Bicycles	no fuel	Electricity	
	Domestic planes	Bioethanol	Jet fuel	Gasoline
Freight transport	Truck	CNG Diesel	Electricity Hydrogen	LNG Gasoline
	Train	Diesel	Electricity	
	Domestic navigation	Diesel	LNG	

Based on the exogenous parameters set by the user, the model calculates the energy demand for each fuel in the target year.

(iii) Mining, quarrying and manufacturing industry

The industry sector is characterised by numerous processes and appliances that are difficult to model with regard to the limited amount of input data available on a federal state level. The FederalPlan model thus refrains from a detailed consideration of useful energy for individual purposes. Instead it includes a disaggregation of final energy into 14 sub-sectors with 8 end-use categories, based on end-use balances available for the whole of Germany [115]. Based on this data, Figure 9 reveals that electricity is mostly used for mechanical energy and process heat, such as cement grinding and electric arc furnaces. In addition, it becomes apparent that especially the process heat end-use is characterised by a large diversity of fuels.

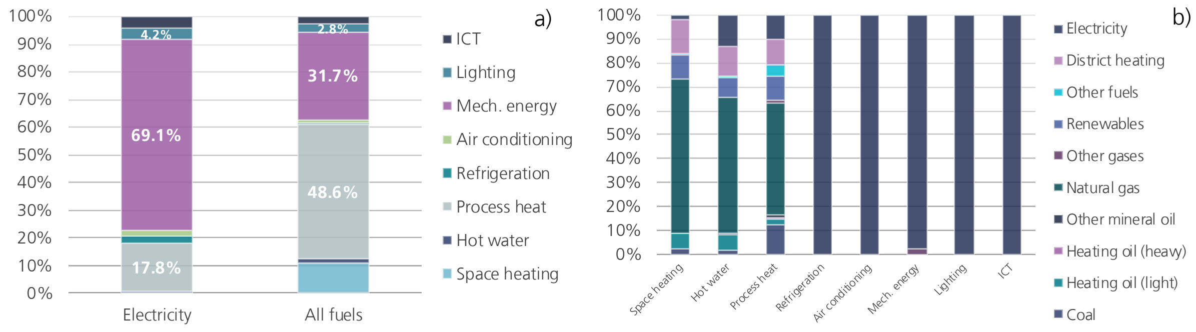


Figure 9. End-use balance for the industry sector in Germany in 2015. Shares in final energy consumption. a) Electricity and total fuels divided by end use. b) End-uses divided by fuel. Source: author's own, based on [115].

These subdivisions into end-uses and fuels are performed for each of the 14 sub-sectors. This requires an adjustment of the energy balances provided for federal states, which are based on a sub-division into 28 sub-sectors according to the German standard WZ 2003 [116] (Table 6).

Table 6. Conversion of sub-sector disaggregation from energy balance (WZ 2003) into end-use balance. Source: author's own, based on [116,116]

Sub-sectors according to end-use balance	Sub-sectors according to WZ 2003
Quarrying, other mining	10.30, 12, 13, 14
Food and tobacco	15, 16
Paper	21
Basic chemicals	24.1
Other chemical industry	24, without 24.1
Rubber and plastic products	25
Glass and ceramics	26.1, 26.2, 26.3
Mineral processing	26 without 26.1, 26.2, 26.3
Manufacture of basic metals	27.1
Non-ferrous metals, foundries	27.4, 27.5
Metal processing	27 without 27.1, 27.4 and 27.5, incl. 28
Manufacture of machinery	29
Manufacture of transport equipment	34, 35
Other segments	All other numbers, excl. 10.10, 10.20, 11.10, 11.20, 23.1, 23.2, 23.3

Overall, the FederalPlan model allows for setting aggregate efficiency improvements per sub-sector, fuel (electricity, other fuels), and end-use. Individual technologies are not explicitly modelled. Exogenous driver parameters are the production values of sub-sectors (in €).

iv) Trade, commerce, services and other consumers (TCS)

A detailed end-use balance for the TCS for Germany is available from [117]. As Figure 10 reveals, about half of its annual final energy demand in Germany in 2015 is used for space heating (47.2%), followed by mechanical energy (17.5%) and lighting (13.5%). In contrast to the household sector, the different end-uses in the TCS sector show a greater diversity with regard to the fuels used, with air conditioning and mechanical energy not only being covered by means of electricity, but also by natural gas. Accordingly, the sector might experience increasing electrification in these end-uses. Moreover, while electricity only covers 3.0% of the final energy needs for space heating, this value can increase with greater market diffusion of heat pumps in long-term scenarios.

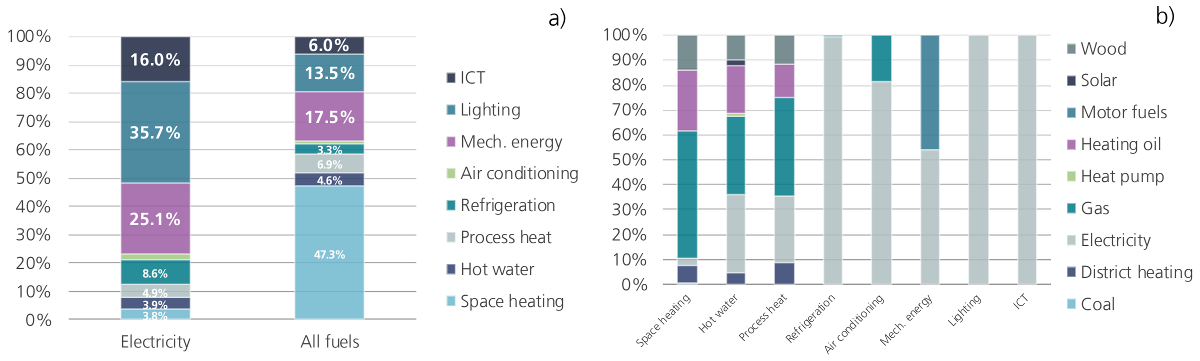


FIGURE 10. End-use balance for the TCS sector in Germany in 2015. Shares in final energy consumption. a) Electricity and total fuels divided by end use. b) End-uses divided by fuel. Source: author's own, based on [117].

In the FederalPlan model, the major scenario driver for the TCS sector is total value added in the service sector (€), while the corresponding structure parameter is the space intensity ($€/m^2$ of commercial space). Again, these data are available from the websites of federal state statistical offices, see for example [52].

TABLE 7. TCS end-use categories and technology options in the FederalPlan model. Source: author's own.

End-use category	Technologies			
Space heating	Coal-fired heater Gas-fired heater	District heating Electric heater	Electric heat pump Oil-fired heater	Solar thermal collector Biomass-fired heater
Hot water	aggregated: kWh/m²			
Process heat	aggregated: kWh/m²			
Refrigeration	aggregated: kWh/m²			
Air conditioning	aggregated: kWh/m²			
Mech. Energy	aggregated: kWh/m²			
Lighting	aggregated: kWh/m²			
ICT	aggregated: kWh/m²			

In accordance with the household sector, the useful energy for space heating in the TCS sector is determined by assigning each fuel in the end-use balance to one supply technology (TABLE 7). The efficiencies of these technologies were derived from [110] and listed in Appendix 7.2. Due to the numerous processes and technologies involved in the remaining end-uses and corresponding data needs, the FederalPlan model refrains from a further disaggregation of these categories. Instead, an aggregated specific energy consumption (kWh/m^2) can be applied in the scenario analyses.

Concluding this section, the FederalPlan model includes a bottom-up accounting framework, distinguishing final energy use by four sectors and multiple end-use categories. Among those, especially the household and the transport sector are modelled with a high degree of technological detail, while scenario assumptions in the industry and the TCS sector remain rather stylised due to absence of data on the manifold processes and appliances involved. Overall, based on the parameters set in the different sectors, the model computes final demand E for a fuel i from the sum of the energy consumption of all technologies j and sectors k.

$$E_i = \sum_j \sum_k E_{i,j,k} \tag{1}$$

The following section on elaborates how the demand projections from the accounting framework are used for projecting hourly electrical load curves.

3.3.2. System load curve

The endogenous projection of hourly load curves in long-term energy system modelling for entire years, based on structural change in the demand sectors, is a relatively recent field of research. In general, three approaches can be distinguished that are used for a continuous hourly projection of regional and national system load curves over the duration of an entire year [11,95].

First, the most common method applied in long-term energy system modelling is to scale historic load curves according to the anticipated future electricity consumption.[31] The underlying assumption of this approach is that the annual load distribution is the same in the future as it was in the past, with only the load levels differing according to demand projections. [118]. Accordingly, the approach neglects changes in the shape of future load curves, making it a highly simplified estimation of future load curves that implies specific error [11,118].

As second approach, as applied in the DESTinEE model [95], is to decompose the system load curve into major economic sectors. Daily profiles are specified for each sector, with summer/winter and weekday/weekend variants to account for differences in human and economic activity. To preserve the unique and anomalous variations of the historic load curve, the residuals between actual and simulated load for 2010 are calculated and then scaled up and applied to the 2050 profiles [95]. While this approach provides some endogenous projection of the load, it neglects the unique profiles of individual applications, such as heat pumps.

Finally, instead of using sector-wide profiles, a third approach decomposes the historic load curve in a more detailed manner by means of application-specific load profiles. According to the application-discrete annual electricity demand projection, the load curve is reassembled for the target year [95]. In this context, applications refer to specific appliances (e.g. television), energy conversion technologies (e.g. heat pump), and processes (e.g. primary aluminium electrolysis). This method is referred to as the *partial decomposition approach* (PDA) [118]. In contrast to methods aiming at a full decomposition of the load curve [119], the PDA does not generate a fully synthetic load curve, but only applies load profiles to a number of appliances, technologies and processes, leaving a remaining load curve of unexplained electricity consumption.

[31] Examples for this approach in the context of Germany and its federal states include Lunz et al. [46] who design a long-term energy planning model and scenarios for Germany and [92] who investigate long-term scenarios for the federal state of Bavaria.

The major advantage of the PDA is its consideration of structural changes in overall annual electricity demand by explicitly modelling the main drivers for load curve transformation, while preserving stochastic outliers and characteristic irregularities from historic load curves [95]. Furthermore, the performance of the PDA is validated comprehensively by means of historical data in [11].[32] In turn, the major problem with the PDA is its great need for input data in terms of application-specific load profiles. This issue can be resolved by drawing upon an internal database of Fraunhofer ISI, featuring about 600 application-specific load profiles for different European countries, originating from field surveys, simulation models and official data [11,95]. Another potential limitation of the PDA is the assumption that the structure of the target year regarding the distribution of weekdays is identical to the base year. This simplification can be considered acceptable for the present research, given that it aims to estimate the load curve for long-term scenarios instead of predicting load curves as close to reality as possible [118]. Considering these benefits, the PDA is selected for projecting future load curves in the FederalPlan model. Its implementation is characterised by the following steps [95] (FIGURE 11):

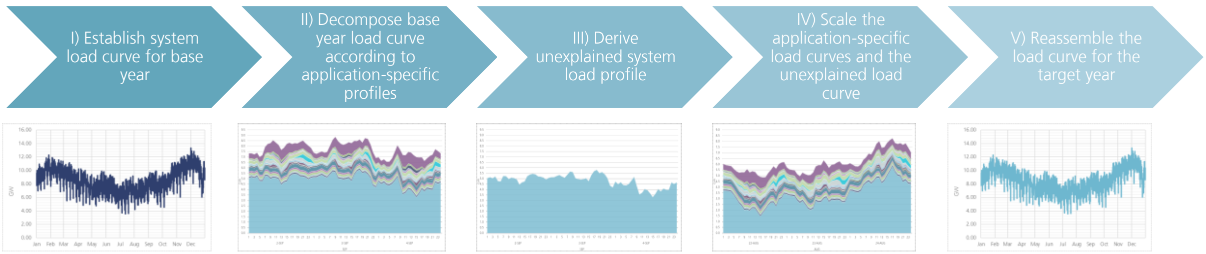


FIGURE 11. Overview of the calculation procedure for load curve projections in the FederalPlan model. Source: author's own.

(I) The hourly system load curve of the base year for the respective federal state or region is obtained.[33]

(II) The base year load curve is decomposed based on the annual electricity demand by the different applications covered, and their respective load profiles. The profiles available for the

[32] In this example, the system load curve for France is modelled for the target year 2010 and compared against the actual historic load curve of this year. The correlation between the modelled and the historic curve equals 95.6% whereas the scaling approach leads to a correlation of only 91.3% [11].

[33] Historic load curve data for European countries can be sourced from ENTSO-E [120]. Load curves on a German federal state level are available from the German transmission system operators (TSO). For example, TransnetBW provides historic load curves from 2010 until 2018 for the federal state of Baden-Württemberg [121]. Note that the other three German TSOs (Tennet, 50 Hertz and Amprion) each cover several federal states. Load curves would thus need to be disaggregated for the respective federal state under consideration.

different end-use sectors are summarised in TABLE 8.[34] In the application example set out in Chapter 1, these applications explain about 42% of the region's total system load in the base year of 2015.

(III) The remaining load curve of unexplained electricity consumption is derived along with its corresponding profile by subtracting the process-specific profiles from the overall load curve.

(IV) The application-specific load curves as well as the unexplained load curve are scaled according to the change in annual electricity demand between base and target year.

(V) The total load for the target year P_{sys} (in GW) at a time step t is reassembled by adding the scaled unexplained load P_{unex} to the aggregated load of the single applications a, with a total of 23 applications as listed in TABLE 8.

$$P_{sys}(t) = P_{unex}(t) + \sum_{a=1}^{23} P_a(t) \tag{2}$$

The sum of the 8760 time steps then equals the cumulated final electricity demand E_{elec} (in GWh) of all applications plus the unexplained load.

$$E_{elec} = \sum_{t=1}^{8760} P_{sys,t} * 1h \tag{3}$$

TABLE 8. Overview of available annual load curves for applications in Germany for use in the partial decomposition approach. Source: author's own.

Households	Transportation	Industry	Trade, commerce, services
Direct electric heating	Electric passenger cars	Cement grinding	Air conditioning
Dish washer	Overhead line trucks	Chemical (generic)	Direct electric heating
Freezer		Electric arc furnace	Heat pumps
Heat pump		Food & tobacco (generic)	Hot water
Hot water		Non-ferrous metals (primary)	Lighting
Lighting		Paper production	
Refrigerator		Rolled steel	
Tumble dryer			
Washing machine			

Based on method outlined, the FederalPlan model projects the hourly electrical load curve for the target year. The next section describes the projection of potentials for demand-side-management.

3.3.3. Practical potential for DSM

Demand side management (DSM) can help deal with residual load variability by shifting demand away from residual load peaks and towards residual load valleys coinciding with power supply

[34] For the industry sector, this requires mapping sub-sector specific end-uses to different processes. For instance, the annual electricity demand for electric arc furnaces is assumed to correspond to the total electrical process heat used in the sub-sector 'Manufacture of basic metals'. This results in an overestimation of the contribution of some load profiles in the overall hourly load curve.

from VRE [78,122].[35] While nowadays the use of DSM is limited in Germany, with existing programmes mostly focusing on large industrial consumers, increasing consideration is being given to account for potentials in the residential and commercial sector with regard to long-term scenario analyses [122]. As part of the FederalPlan modelling tool, this section describes the approach chosen for providing a detailed endogenous assessment of long-term DSM potentials in German federal states, drawing upon the technology mix obtained from the accounting-based demand projection module. The focus of this assessment is the *practical potential*,[36] with the parameters determined being applied at a later stage in the power system module of the FederalPlan tool to represent DSM as a flexibility option (Chapter 3.4.2).

Research in the field of energy systems modelling commonly attributes DSM potentials to appliances and processes in the residential, industry, and tertiary sectors, with electric vehicles often being included in the residential sector. Approaches range from detailed load profile analyses [124] to aggregated approaches for different processes and end-uses [112,122]. The latter category seems sufficient for the present study, considering its objective of providing stylised estimates for scenario studies rather than rigorous numbers. The following sub-sections describe the potential assessment procedure for the three demand sectors, with each section following two essential steps: (i) Identification of DSM-relevant processes and appliances, (ii) characterisation of these processes and appliances with regard to their potential load increase (negative balancing power), load reduction (positive balancing power) and the typical shifting times. Load reduction can be realised either by shedding or delaying demand, whereas load increase is equivalent to advancing operation of processes or devices [122,123].

Households (residential sector)

Following Styczynski et al. [112], residential loads are quantified in a bottom-up approach. Devices and appliances considered in the FederalPlan model include refrigerators, freezers, tumble dryers,

[35] Some authors make a distinction between demand response, which is focused on load flexibility and short-term consumer action, and demand side management, which also comprises energy efficiency measures and regular utility-driven changes in demand pattern [2,123]. Both terms are used interchangeably in this study, referring to changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [122].

[36] Research usually distinguishes different potential types [22,69]. Following Gils [122] the following definitions are applied in the present analysis: the theoretical potential comprises all facilities and devices of the consumers suitable for DSM, while the technical potential includes only those that can be controlled by the existing ICT infrastructure. A subset of the technical potential is the economic potential of all DSM consumers that can be operated in a cost-efficient way. Another subset of the technical potential arises from the acceptance of load interventions. This effectively usable, practical potential is the focus of the present assessment.

room air-conditioning, circulation pumps for heating systems, hot water boilers and electric vehicles (EVs).[37] For electric vehicles, the analysis assumes a vehicle-to-grid (V2G) configuration, in which vehicle batteries can be discharged to feed power to the grid. This goes beyond a grid-to-vehicle (G2V) configuration, in which fleets of EVs are operated as a DSM option by enabling a shifting of the charging times [77]. The DSM potential per appliance is determined as follows: First, the total power $P_{\max}$ of all appliances of a given type i is determined according to the number of households N_{HH}, the number of appliances per household N_i and the typical power per appliance P_i:

$$P_{max,i} = N_{HH} * N_i * P_i \tag{4}$$

Subsequently, the theoretical potential for positive balancing power (i.e. the load that can be reduced) $P_{pos,th,i}$ is determined by the maximum power $P_{max,i}$ and its average utilisation according to the number of full load hours per year N_{FLH};

$$P_{pos,th,i} = P_{max,i} * (N_{FLH,i}/8760h) \tag{5}$$

The theoretical potential for negative balancing power (i.e. the load the can be increased) $P_{neg,th,i}$ is based on the difference between the total installed power and the theoretical positive balancing power:

$$P_{neg,th,i} = P_{max,i} - P_{pos,th,i} \tag{6}$$

Afterwards, each theoretical potential is multiplied with two factors (ranging between 0 and 1), yielding the practical potentials $P_{pos,pr,i}$ and $P_{neg,pr,i}$. The feasibility *factor* $\sigma_{feasibility}$ considers practical and economic constraints in the implementation, reflecting that not all appliances of a certain technology are appropriate for DSM [112]. The acceptance *factor* $\sigma_{acceptance}$ indicates the consumer-side consent with an external control of their devices and appliances. It brings together different influences, including general scepticism towards access to household-related data and business models that draw on the participation of customers [77,112].

In a final step, typical shifting times τ_i are analysed for the technologies i considered (total of n technologies). These are derived from [112], ranging from 15 minutes for refrigerators to one hour

[37] This selection excludes two types of appliances. On the one hand, devices with a load profile inappropriate for DSM are not considered, e.g. washing machines and dish washers, for which the maximum power is not used at the beginning of the utilisation process [112]. On the other hand, heat supply technologies such as heat pumps and electric heaters, due to their seasonal fluctuations in use between heating periods and non-heating periods. This would have required a more elaborate approach for potential assessment, which is beyond the scope of the present analysis. In turn, air conditioning, circulation pumps and hot water boilers are assumed to cover stable load patterns throughout the year.

for tumble dryers. In order to obtain a common metric for the practical DSM potentials $P_{pos,pr}$ and $P_{neg,pr}$, the technology-discrete potentials (positive and negative) are aggregated to a common shifting time of 6 hours, with proportionally reduced power if the shifting time is increased:[38]

$$P_{pos,pr} = \sum_{i=1}^{n} \frac{P_{pos,pr,i} * \tau_i}{6h} \qquad (7)$$

$$P_{neg,pr} = \sum_{i=1}^{n} \frac{P_{neg,pr,i} * \tau_i}{6h} \qquad (8)$$

TABLE 9. Default parameters for DSM-processes in the residential sector in 2050. Source: author's own, based on [112].

Process	Max. power per unit (P_i)	Full load hours per year ($N_{FLH,i}$)	Max. shiftable time (τ_i)	Feasibility factor ($\sigma_{feasibility}$)
	[kW/unit]	[h/a]	[hours]	[-]
Refrigerator	0.15	3,179	0.25	0.4
Freezer	0.15	2,920	0.25	0.4
Tumble dryer	1.15	204	1	0.4
Air conditioner	1.70	450	0.25	0.4
Circulation pump	0.01	6,000	0.25	0.4
Hot water boiler	2.00	1,059	1	0.1
Electric vehicle	5.00	-	2	1.0

TABLE 9 compiles the default parameters set in the FederalPlan model for DSM-appliances in the residential sector.

Industry sector

The processes considered by the FederalPlan tool with regard to energy-intensive industries include cement mills, pulp grinding, steel melting in electric arc furnaces, as well as chlorine electrolysis. In addition, flexible loads in the cross-sectional technologies cooling and ventilation are evaluated. The parameters for this sector essentially draw upon Buber et al. [82], who performed a DSM potential assessment for energy-intensive industry processes in Germany. Their data is based on site inspections, online surveys (>300 responses) and interviews with energy suppliers and service providers.[39] The calculation procedure here is broadly consistent with the steps described for the residential sector, with two differences applying. First, the practical

[38] The underlying assumption being that load shifting is prolonged by sequencing multiple responses. For instance, a large number of storage warehouses in the tertiary sector tolerate a moderate temperature increase only for a limited amount of time. A prolonged demand reduction can be achieved by setting the response of a new group of storage warehouses after the first group has reached the limit [78,112].

[39] Estimating the DSM potential in the industry sector is generally considered more complicated than in the household and tertiary sector. On the one hand this is due to a lack of publicly available data for essential industrial processes. Single DSM estimation studies for the industry sector are thus restricted to small samples. On the other hand, considering the target year 2050, there are multiple options for electrification of industrial processes that have not been quantified yet. As a result, potential estimates for industrial DSM are often regarded as conservative in their predictive properties [112].

potential for reducing load (positive balancing power) is approximated by a ratio of potential (MW) and annual energy demand (GWh) for the specific process.[40] Second, following [112], the practical potential for increasing load (negative balancing power) is derived under the assumption that reduced production is compensated within 24 hours.[41] In accordance with the residential sector, a six hour shifting time is assumed for merging the different processes into a single metric.

TABLE 10. Default parameters for DSM-processes in the residential sector in 2050. Source: author's own, based on [82,125].

Process	Approximated power-to-energy-ratio	Max. shiftable time (τ_i)
	MW/GWh	hours
Cement (raw and cement mill)	0.07	4
Paper (pulp grinder)	0.02	2
Steel (electric arc furnace)	0.08	2
Chlorine (electrolysis)	0.07	2
Crosss-sectional technologies	0.01	1

TABLE 10 summarises the default parameters assumed for industry processes in the FederalPlan model.

Tertiary sector (trade, commerce, services)

The tertiary sector holds potential for DSM with regard to cross-section processes, such as providing heating and cooling. Other potential technologies include air conditioning or compressed air for mechanical use [77]. Following [112], generic processes included in the FederalPlan model include air conditioning, mechanical energy, process cooling, process heating, and space heating. It is assumed that the appliance uses for air-conditioning and space heating are independent of outside temperature. The assessment of practical DSM potentials corresponds to the procedure described for the residential sector, drawing upon installed power, average utilisation, as well as exogenous feasibility and acceptance factors. A six hour shifting time is assumed for merging the different processes.

TABLE 11. Default parameters for DSM-processes in the tertiary sector in 2050. Source: author's own, based on [112].

Process	Full load hours per year ($N_{FLH,i}$)	Max. shiftable time (τ_i)	Feasibility factor ($\sigma_{feasibility}$)
	[h/a]	[hours]	[-]
Air conditioning	630	0.25	0.4
Mech. energy	1,130	0.08	0.1
Process cooling	5,840	0.08	0.4
Process heating	2,920	0.08	0.1
Space heating	640	0.25	0.4

[40] Buber et al. [82] estimate the practical DSM potential cement grinding, pulp grinders, electric arc furnaces and chlorine electrolysis for the whole of Germany (in MW), however, without providing a useful reference. Therefore, the annual energy demand for these processes in Germany is derived from [125] (in GWh), enabling a rough approximation of the potential by MW/GWh ratios.

[41] For example, a positive balancing power of 3.4 GW and a shifting time of 2 hours yield a shifted energy of 6.8 GWh. The negative balancing power then amounts to 0.3 GW (6.8 GW/24 h) [112]

The default parameters assumed for the tertiary sector are compiled in TABLE 11. In conclusion, relying on the methodology outlined in this chapter, the FederalPlan tool identifies the practical DSM potential for individual processes and appliances. The aggregate metrics for positive and negative balancing power are utilised in the cost-optimisation procedure set out in Chapter 3.4.2.

3.4. Supply side implementation

The power supply side of the FederalPlan modelling tool comprises two essential components, which are elaborated in detail in the following. In a first step, based on GIS data, the power generated from VRE is modelled for the target year and subtracted from the electrical system load to obtain the hourly residual load (Section 3.4.1). Subsequently, the algorithm for cost-based technology assignment computes an adequate capacity mix for balancing power generation and demand (Section 3.4.2).

3.4.1. VRE generation and residual load

In order to identify the need for flexibility options in future power systems, the model computes a residual load curve. The gross residual load $P_{res,gross}$ at time t is defined as the difference from the system load $P_{load}(t)$, the fluctuating generation of wind and solar power $P_{VRE}(t)$ and the slightly fluctuating infeed from run-of-river hydro power plants without hydro storage $P_{hydro}(t)$ [46,78].[42]

$$P_{res,gross}(t) = P_{load}(t) - P_{VRE}(t) - P_{hydro}(t) \tag{9}$$

The hourly system load is based on the load curve projection set out in Chapter 3.3.2. VRE generation is split up into PV and wind power:

$$P_{VRE}(t) = P_{PV}(t) + P_{wind}(t) \tag{10}$$

Hourly infeed time series for both technologies and for custom locations across Europe are available from the open-source platform *renewables.ninja* [126]. The platform's PV section is based on [94], where the authors use global meteorological reanalysis and temperature data to produce hourly PV simulations across Europe. The data allows for choice of the base year, module tilt and module orientation (azimuth). By default, the FederalPlan model uses a mixture of 9 configurations customisable by the user, reflecting different tilt angles and orientations at a given federal state location (TABLE 12).

[42] The underlying assumption is that VRE generators are dispatched first in the merit order, due to their low short-run cost as well as priority dispatch ensured in Germany [78].

TABLE 12. Default PV assumptions for tilt angle and orientation (azimuth) of PV modules installed in 2050. Source: author's own, based on [46].

[% of installed capacity]	Tilt angle		
Orientation	30°	45°	60°
South	30%	20%	20%
East	5%	5%	5%
West	5%	5%	5%

Wind infeed series are also readily available from the platform. These simulations are based on the bias-corrected reanalysis of current and future wind power output provided in [127]. User inputs required are the model region, the turbine hub height as well as the turbine model with different characteristics and power losses. By default, the FederalPlan model assumes a turbine height of 100 m and the characteristics of an Enercon E-115 onshore turbine, being among the top-three of most commonly installed wind turbine models in Germany in 2017 [128]. After having set the framework parameters, $P_{PV}(t)$ and $P_{wind}(t)$ can be determined, respectively, by multiplying the hourly capacity factor $CF(t)$ with the exogenously defined rated capacities:

$$P_{PV}(t) = P_{el,PV} * CF_{PV}(t) \quad (11)$$

$$P_{wind}(t) = P_{el,wind} * CF_{wind}(t) \quad (12)$$

The relatively constant hourly capacity factors for hydro power are taken from [129]. The power output calculation is analogous to Equations (11) and (12). For calculating the LCOE at a later stage of the model, cost parameters are assumed for VRE and hydro installations, displayed in Appendix 7.2. Following [130] and [46], the LCOE for PV is composed of the capital costs for the module $C_{cap,mod}$, capital costs for the inverter $C_{cap,inv}$, fixed annual operation and maintenance costs, and the total electricity generated over the year $E_{el,PV}$.

$$LCOE_{PV} = \frac{C_{cap,mod} + C_{cap,inv} + C_{O\&M,PV}}{E_{el,PV}} \quad (13)$$

The annuity method [43] is used for calculating the annual discounted value of the investments, with i denoting the discount rate and u_{mod} and u_{inv} the respective lifetimes of the components. The capital costs for the module can then be deduced from the installed PV capacity $P_{el,PV}$ and the specific module costs c_{mod}. The capital costs of the inverter are based on the specific inverter costs c_{inv} and the specific balance of system costs c_{bal}, both measured in $€/kW_p$. Annual O&M costs are calculated from the installed capacity and the specific O&M costs $c_{O\&M}$, expressed in $€/(kW_p * a)$.

$$C_{cap,mod} = P_{el,PV} * c_{mod} * \frac{(1+i)^{u_{mod}} * i}{(1+i)^{u_{mod}} - 1} \quad (14)$$

[43] The annuity method can be considered as a simplification of the capital value method for calculating the LCOE [131]. Essentially, it assumes constant electricity generation and constant O&M expenses throughout the entire technology lifetime.

$$C_{cap,inv} = P_{el,PV} * (c_{inv} + c_{bal}) * \frac{(1+i)^{u_{inv}} * i}{(1+i)^{u_{inv}} - 1} \tag{15}$$

$$C_{O\&M} = P_{el,PV} * c_{O\&M} \tag{16}$$

The LCOE for wind power is determined based on the installed capacity $P_{el,wind}$, annual generation $E_{el,wind}$, installation costs c_{inst}, grid access costs c_{grid} (both expressed in $€/kW$), the rent for land use c_{rent} and other specific O&M costs $c_{O\&M}$ (both expressed in $€/MWh$) as well as the turbine lifetime u_{wind}.

$$LCOE_{wind} = \frac{C_{cap,wind} + C_{O\&M,wind}}{E_{el,wind}} \tag{17}$$

$$C_{cap,wind} = P_{el,wind} * \left(c_{inst} + c_{grid}\right) * \frac{(1+i)^{u_{wind}} * i}{(1+i)^{u_{wind}} - 1} \tag{18}$$

$$C_{O\&M,wind} = E_{el,wind} * (c_{rent} + c_{O\&M}) \tag{19}$$

Overall, each cost parameter can be customised by the user to reflect different scenario boundary conditions. After the calculation of the residual load and the LCOE, electricity imports can be set in the model. This is done by defining a power import factor γ that is multiplied with the maximum load P_{max} (in GW). For each time step, either this product or the gross positive residual load $P_{res,gross,pos}$ (in GW) in a time step t is selected to give a steady supply of imports. Summed up, this yields the total amount of imports E_{imp} (in GWh). Alternatively, using a numerical solver algorithm such as Excel's *Goal Seek* function, the total import energy can be defined while determining the import factor endogenously.

$$P_{imp}(t) = \min \begin{cases} P_{res,gross,pos}(t) \\ \gamma * P_{max} \end{cases} \tag{20}$$

$$E_{imp} = \sum_{t=1}^{8760} \mathrm{P_{imp,t}} * 1h \tag{21}$$

As a result, the positive residual load with subtracted imports $P_{res,pos}$ (in GW) at a time step t is defined by the initial residual load $P_{res,gross,pos}$ minus the hourly imports P_{imp}.

$$P_{res,pos}(t) = P_{res,gross,pos}(t) - P_{imp}(t) \tag{22}$$

The next section explains how this positive residual load is covered by flexible power generators, using the algorithm for cost-based technology assignment.

3.4.2. Cost-based technology assignment

Following Lunz et al. [46], the algorithm for cost-based technology assignment consists of three steps: (i) the positive residual load which has to be met by power generators is divided into 50 'load bands'; (ii) all available power generating technologies are technically as well as economically characterised for the specific requirements of the residual load bands; (iii) the technologies are ranked for each load band based on full costs and under the constraint that the positive residual load is covered at each of the 8760 hourly time steps of the year.

To assure that power demand is met at all times, the positive residual load at a time step t needs to be zero at all times [46]. For this purpose, the model divides the positive residual load $P_{res,pos}$ is into 50 load bands: [44]

$$P_{res,pos}(t) = \sum_{n=1}^{50} P_{res,pos,n}(t) \tag{23}$$

FIGURE 12 illustrates this procedure using a subdivision of 10 load bands. Starting at the lowest load band $P_{res,pos,1}$, the technology that is able to cover the entire hourly load in a specific load band at minimal costs is assigned. For this purpose, the model performs a comparative cost assessment of all available flexibility technologies that are able to cover the whole load band. Subsequently, this process is iterated for each load band. Flexibility technologies are conventional thermal power plants, CHP plants, storage systems and DSM, with the latter two using their ability to shift surpluses from negative residual load (surplus VRE generation) to times with positive residual load [46]. Calculation of the respective technology costs is again based on the annuity method and covers investment, annual fixed and variable operation and maintenance costs. For storage technologies, the this calculation involves numerical optimisation of the dimensioning in terms of storage size and charging power, in order to ensure that these can be sufficiently recharged at lowest costs [4,46].

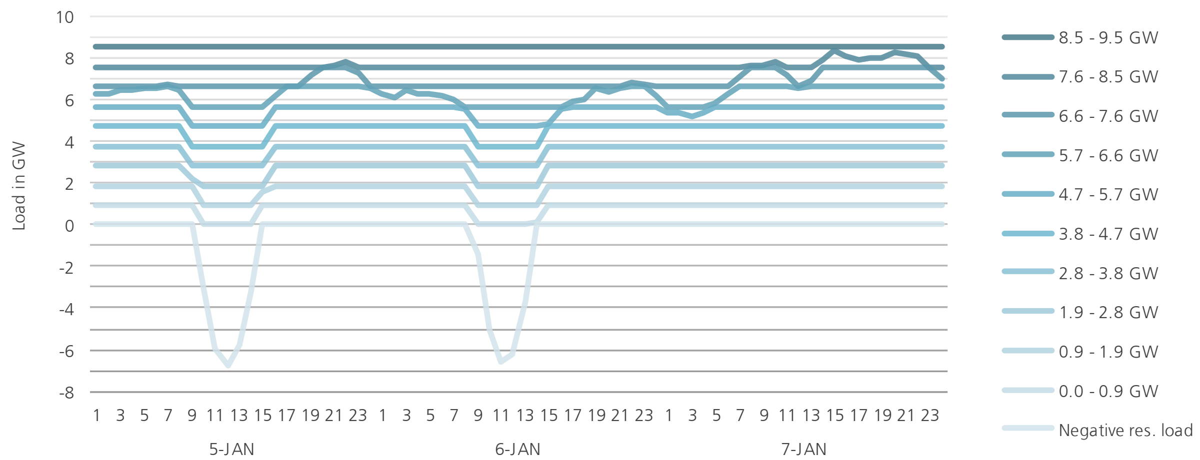


FIGURE 12. Illustrative hourly subdivision for the federal state Baden-Württemberg using 10 load bands minus the negative residual load (surplus VRE). Source: author's own.

[44] In principle, this number is not compulsory and was selected as a potential compromise between computational feasibility and optimality of the solution.

Once the last positive residual load band is assigned and all energy needed for recharging the storage systems is subtracted from the negative residual load hour by hour, a negative residual load remains. In this case, a power-to-heat (P2H) and power-to-gas (P2G) technologies come into effect, which are able to operate with negative residual loads. Finally, as a last resort, VRE infeed is curtailed if no cost-effective power-to-X technology option is available [46]. In the following, the cost calculation for each technology type is described in detail.

Type 1: Thermal power plants

Thermal plants cover a positive residual load band by means of fuel combustion and power generation, involving energy losses and CO_2-emissions. FIGURE 13 provides a schematic of this process. The FederalPlan includes the following thermal power plant types: steam turbines (ST, fired by lignite or hard coal, with or without carbon capture and storage (CCS)), open-cycle gas turbines (OCGT, fired by natural gas or biomethane), combined cycle gas turbines (CCGT, natural gas or biomethane), engine power stations (natural gas or biomethane), and biomass power plants (wood-fired).[45]

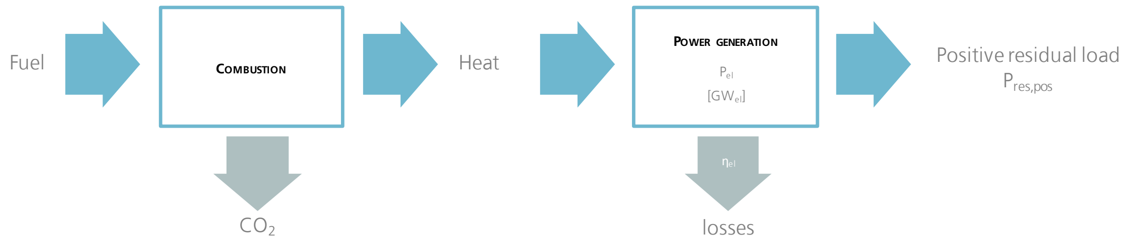


FIGURE 13. Operation principle of thermal power plants in the FederalPlan model. Source: author's own, based on [4,46].

Technically, the technologies are characterised by their conversion efficiency and specific CO_2 emissions. Economic parameters include the specific investments costs, fixed and variable costs. The full costs of a power plant (PP) technology in a load band n consist of the capital cost C_{cap}, the annual fuel costs C_{fuel}, the annual costs for CO_2-Emissions C_{CO2}, annual fixed operation and maintenance (O&M) costs $C_{O\&M,fix}$ as well as variable operation and maintenance costs $C_{O\&M,var}$, depending on the number of warm and cold starts per load band [46].

$$C_{PP,n} = C_{cap} + C_{fuel} + C_{CO2} + C_{O\&M,fix} + C_{O\&M,var} \tag{24}$$

The annuity method is used for calculating the annual discounted value of the investment, where P_{el} is the maximum system load in the load band in GW_{el}, c_I is the specific investment cost in $€/GW_{el}$, i is the discount rate and u is the technological lifetime in years:

[45] Nuclear power plants are disregarded in the model, considering that the German government decided to phase out nuclear power by 2022 in response to the nuclear disaster of Fukushima [70].

$$C_{Cap} = P_{el} * c_I * \frac{(1+i)^u * i}{(1+i)^u - 1} \tag{25}$$

Annual fuel costs are calculated based on the delivered electrical energy E_{el} in GWh, the electrical conversion efficiency η_{el}, and the specific fuel cost $c_{fuel,th}$ in €$/GWh_{th}$:

$$C_{fuel} = \frac{E_{el}}{\eta_{el}} * c_{fuel,th} \tag{26}$$

Costs for CO_2-emissions are based on the input of primary energy, the CO_2-intensity of the respective fuel in t_{CO2}/GWh_{th} as well as c_{CO2}, the cost per tonne of CO_2:

$$C_{CO2} = \frac{E_{el}}{\eta_{el}} * e_{CO2} * c_{CO2} \tag{27}$$

Annual fixed operation and maintenance costs are calculated as a percentage $c_{O\&M}$ of the overall investment:

$$C_{O\&M,fix} = P_{el} * c_I * c_{O\&M} \tag{28}$$

The variable operation and maintenance costs account for all costs related to a starting process of the power plant. These include higher deterioration, extra fuel feed and extra labour costs [46]. The model distinguishes between starting processes from a cold and warm state, where the minimum idle time for a cold start is set to 24 hours. The calculation is based on P_{el}, the number of cold and warm starts n_{start} as well as the specific costs for each start c_{start} in €$/(GW_{el} * event)$.

$$C_{O\&M,var} = P_{el} * (n_{start,cold} * c_{start,cold} + n_{start,warm} * c_{start,warm}) \tag{29}$$

The detailed technology parameters set in the model by default are based on [46] and displayed in Appendix 7.2.

Type 2: Combined heat and power plants

Cogeneration of heat and power (CHP) is used to supply electricity to the power grid, as well as heat to customers in the residential, tertiary and industry sectors (FIGURE 14). Its implementation in the FederalPlan model involves two essential step. First, the annual demand for distributed heat is determined from the demand module of the FederalPlan model. A distinction is made between low temperature heat (used for space heating and hot water supply in the residential and tertiary sectors), as well as high-temperature process heat (used in the single branches of the industry sector) [96,132]. The annual demands obtained for these two categories are transposed into hourly heat load curves, using a normalised profile for the former, and a constant load curve for the latter.[46]

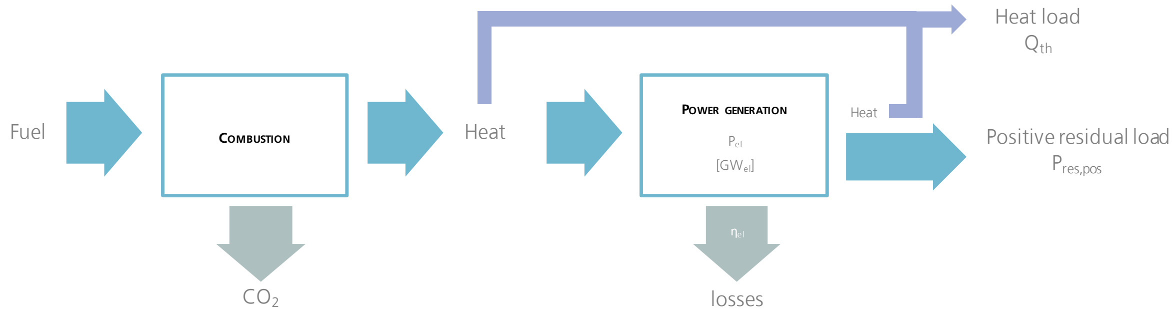


FIGURE 14. Operation principle of cogeneration plants in the FederalPlan model. Source: author's own.

Subsequently, the model assigns CHP technologies to the levels of power and heat demand. For the supply of district heat to households and commercial buildings in the TCS sector the model includes a combined cycle gas turbine (CCGT), a hard coal-fired steam turbine, and a gas turbine. For the industry sector the model includes a gas-fired engine CHP [4]. Steam turbine and combined-cycle CHPs are modelled as extraction-condensation turbines, which are characterised by variable heat supply. In cases of low heat demand, they can be operated in pure condensing mode, generating electricity only [134].[47] To limit computational complexity, power loss from heat extraction in these turbines is disregarded in the calculations.[48]

In the cost-based technology mapping algorithm, CHPs are assumed to operate primarily to produce electricity in the respective load band n.[49] Heat $P_{th,CHP}$ (in GW_{th}) can be extracted at a time step t if there is simultaneous heat demand Q_{th} in the heat demand curve and power demand in the load band $P_{res,pos}$. The inverse of the electricity to heat ratio ρ indicates how much thermal power is produced per unit of electric power [134]. For simplification, ρ is assumed to be constant at every time step.

[46] The normalised load curve for residential and tertiary demand is covers the year 2015 in Germany and is based on internal communication at Fraunhofer ISI [133]. No outside temperature-related parametrisation of the load curve is performed for the scenario target years. Following [132], heat load in the industry sector is assumed to follow a constant heat demand throughout the year.

[47] In contrast to extraction-condensation turbines, back-pressure turbines are characterised by a coupled generation of heat and power. For the sake of simplicity, this CHP circuit type is not considered in the model.

[48] The power loss factor β indicates how much electricity is lost when extracting heat in comparison to running the CHP in condensing mode. This loss occurs because steam is extracted before the turbine, making it unavailable for electricity generation [22,134].

[49] This is a simplification, considering that in reality industrial CHP produces heat for industrial processes, with the power generation following variations of the industrial heat demand [77].

$$P_{th,CHP}(t) = min \begin{cases} P_{res,pos,n}(t) * 1/\rho \\ Q_{th}(t) \end{cases} \tag{30}$$

The annual generation of heat from CHP $E_{th,CHP}$ in GWh is the sum of thermal power generated at every hour of the year:

$$E_{th,CHP} = \sum_{t=1}^{8760} P_{th,CHP}(t) * 1h \tag{31}$$

Analogous to conventional power plants, CHP costs $C_{CHP,n}$ for a load band n are based on the electrical conversion efficiency, the electricity generated, as well as the specific costs for capital, fuel, CO_2, as well as fixed and variable O&M (see Equations (25) to (29). Capital costs for district heating infrastructure are neglected. Cost allocation for the cogenerated heat is based on the Residual Value method [135] in which a heat bonus B_{heat} in € is subtracted from the total costs for avoided heat production in an auxiliary heat-only boiler.

$$C_{CHP,n} = C_{cap} + C_{fuel} + C_{CO2} + C_{O\&M,fix} + C_{O\&M,var} - B_{heat} \tag{32}$$

B_{heat} is based on the amount of heat generated $E_{th,CHP}$, the fuel cost of the avoided heat-only boiler $c_{fuel,th}$ in €$/GWh_{th}$ and the thermal efficiency of the heat boiler η_{th}.

$$B_{heat} = E_{th} * \frac{c_{fuel,th}}{\eta_{th}} \tag{33}$$

If not enough CHP plants are installed in the cost-based technology mapping to cover heat demand in all sectors, the model assumes the use of a gas-fired heat-only boiler. Alternatively, power-to-heat (P2H) facilities can be installed, this procedure is described further below. In general, calculations for the total cost of district heat supply are beyond the scope of the model, no economic calculations are attached to the boiler deployment. The detailed technical and economic parameters for CHP technologies are based on [46] and [136] are listed in Appendix 7.2.

Type 3: Storage technologies

Storage encompasses all technologies that can absorb electrical energy at a given time and return it as electrical energy at a later stage [78]. Its major usage is load shifting, i.e. decreasing the power usage of a time period while increasing the one of another [137]. Based on [4,46], the FederalPlan model features the following storage technologies: pumped hydro-electric storage (PHES), adiabatic compressed air energy storage (CAES), hydrogen storage, methane storage (using either a gas turbine or CCGT for reconversion into electricity) and a generic battery storage type. In addition, DSM is treated as functional storage with limited shifting time, see further below.

In technical terms, storage technologies are characterised by their charging and discharging efficiencies (η_{charge} and $\eta_{discharge}$), the minimum state-of-charge of the storage unit ($SOC_{min}\ in$ %), as well as by the dimensions of the charging ($P_{el,charge}$ in GW), storage ($E_{storage}$ in GWh) and discharging capacity ($P_{el,discharge}$ in GW) for a given load band.[50] Storage technologies cover a positive load band by charging electricity either from VRE surplus (negative residual load) or from thermal power plants with idle operation already installed in lower load bands (FIGURE 15). If charging from power plants occurs, the costs and CO_2-emissions of the power plant mix below the current load band are taken into account. Energy from negative residual load is assumed to have zero costs and zero CO_2 emissions – considering that this power is generated from renewable energies only and that their investment and O&M costs are accounted for in the overall cost calculation [46].

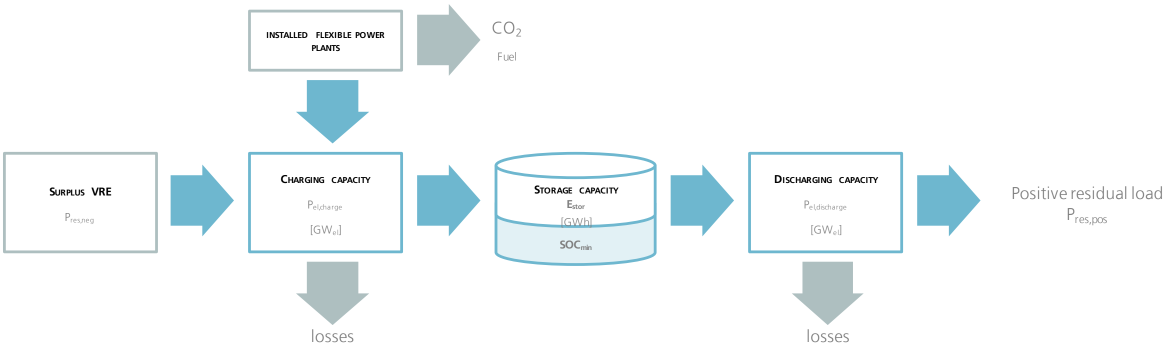


FIGURE 15. Operation principle of storage technologies in the FederalPlan model. Source: author's own, based on [4,46].

In economic terms, the costs of a storage system comprise capital costs C_{cap}, fixed operation and maintenance $C_{O\&M}$, and costs for recharging from thermal power plants C_{PP}:

$$C_{storage,n} = C_{cap} + C_{O\&M} + C_{PP} \tag{34}$$

The investment includes the charging unit, the storage unit and the discharging unit:

$$C_{Cap} = C_{cap,charge} + C_{cap,storage} + C_{cap,discharge} \tag{35}$$

Capital costs are determined similar to those of thermal power plants with individual lifetimes assumed for each of the three components. $P_{el,charge}$ and $P_{el,discharge}$ denote the respective capacities (GW), $E_{storage,gross}$ indicates the storage capacity (GWh), c represents the corresponding specific costs in $€/GW$ and $€/GWh$, respectively. The lifetime of each component is u and i denotes the discount rate.

$$C_{cap,charge} = P_{el,charge} * c_{charge} * \frac{(1+i)^{u_{charge}} * i}{(1+i)^{u_{charge}} - i} \tag{36}$$

[50] Taking the example of pumped hydro-electric storage, the energy in the storage unit corresponds to the amount of water contained in the reservoir, while the charging and discharging capacities are determined by how much water can flow in and out of the reservoir in one moment [78].

$$C_{cap,storage} = E_{storage,gross} * c_{storage} * \frac{(1+i)^{u_{storage}} * i}{(1+i)^{u_{storage}} - i} \quad (37)$$

$$C_{cap,discharge} = P_{el,discharge} * c_{discharge} * \frac{(1+i)^{u_{discharge}} * i}{(1+i)^{u_{discharge}} - i} \quad (38)$$

Fixed operation and maintenance is again represented by a percentage $c_{O\&M}$ of the initial investment:

$$C_{O\&M} = c_{O\&M} * (P_{el,charge} * c_{charge} + E_{storage,gross} * c_{storage} + P_{el,discharge} * c_{discharge}) \quad (39)$$

The costs for recharging from power plants in lower load bands is determined from the total amount of energy charged E_{PP} (in GWh) from them, and their specific costs c_{PP} (in $€/GWh$).

$$C_{PP} = E_{PP} * c_{PP} \quad (40)$$

The specific costs comprise the average fuel and CO_2 costs of the installed power plant mix below the current load band, weighted by the total amount of energy that these are capable of delivering. Default technology and cost parameters assumed for storage technologies are listed in Appendix 7.2.

The model implementation of storage technologies involves numerical optimisation in order to find the cost-optimal size of the charging and the storage capacity for a given load band. This optimisation, nested in the overall technology assignment algorithm, is subject to a number of variables, summarised below.

Table 13. Nomenclature for optimisation of charging and storage capacities. Source: author's own.

Variable	Meaning	Unit	Variable	Meaning	Unit
$\boldsymbol{E_{storage,gross}}$	storage capacity installed	GWh	$P_{el,charge}$	charging capacity installed	GW
$\boldsymbol{E_{storage}(t)}$	storage level at time t	GWh	η_{charge}	charging efficiency	%
$\boldsymbol{P_{charge,VRE,net}(t)}$	charge from VRE incl. losses	GW	$P_{VRE}(t)$	surplus VRE available	GW
$\boldsymbol{P_{charge,PP,net}(t)}$	charge from power plants incl. losses	GW	$P_{PP}(t)$	power plant capacity available	GW
$\boldsymbol{P_{discharge,net}(t)}$	storage discharge incl. losses	GW	$P_{res,pos}(t)$	power demand; system load	GW
$\boldsymbol{SOC_{min}}$	minimum state-of-charge	%	$\eta_{discharge}$	discharging efficiency	%
			$P_{storage,gross}$	storage discharge excl. losses	GW

The storage level at a given time step is composed of the previous state of charge, the charging from negative residual load (VRE), the charging from power plants and the power discharged:

$$E_{storage}(t) = E_{storage}(t-1) + P_{charge,VRE,net}(t) + P_{charge,PP,net}(t) - P_{discharge,net}(t) \quad (41)$$

Storage technologies are assumed to have their minimum state-of-charge at the start of the time series:

$$E_{storage}(0) = E_{storage,gross} * SOC_{min} \quad (42)$$

Charging from VRE is restricted by the installed charging capacity, the availability of VRE, and the storage space remaining in the storage unit:

$$P_{charge,VRE,net}(t) = min \begin{cases} P_{el,charge} \\ P_{VRE}(t) * \eta_{charge} \\ [E_{storage,gross} - E_{storage}(t-1) + P_{discharge,net}(t)] \end{cases} \tag{43}$$

Charging from power plants is initiated only if there is no simultaneous VRE supply and if the demand in the upcoming 24 hours is greater than 0 (in other words, storage facilities are assumed to have a foresight of 24 hours regarding load peaks):

$$P_{charge,PP,net}(t) = \begin{cases} min \begin{cases} P_{el,charge} \\ P_{PP}(t) * \eta_{charge} \\ [E_{storage,gross} - E_{storage}(t-1) + P_{discharge,net}(t)] \end{cases} & if\ P_{VRE}(t) = 0\ and \left(\sum_{t}^{t+24} P_{res,pos} \right) > 0 \\ 0 & else \end{cases} \tag{44}$$

Discharging must not make the storage unit fall under its minimum state-of-charge and must correspond to system load:

$$P_{discharge,net}(t) = min \begin{cases} E_{storage}(t-1) - E_{storage,gross} * SOC_{min} \\ P_{res,pos}(t)/\eta_{discharge} \end{cases} \tag{45}$$

Gross discharging is determined via the discharging efficiency:

$$P_{discharge,gross}(t) = P_{discharge,net}(t) * \eta_{discharge} \tag{46}$$

After having set up these storage balance equations in the model, a non-linear optimisation is applied to determine the cost-optimal dimensions of charging and storage capacity for a given load band and storage technology. First, the discharging capacity is set according to the maximum load of the respective load band n:

$$P_{el,discharge} = max(P_{res,pos,n}) \tag{47}$$

Subsequently, the objective function of minimising the total costs per technology and load band n is defined. This objective is subject to the power balance, i.e. positive residual needs to be covered at every time step t.

$$\begin{gathered} min(C_{storage,n}) \\ s.t. \\ P_{discharge,gross,n}(t) = P_{res,pos,n}(t) \end{gathered} \tag{48}$$

The optimisation is performed for each storage technology and load band using the *Solver* tool in Excel. After this optimisation is completed and if storage technologies are installed as cost-optimal options in the technology mapping, the hourly negative residual load (surplus VRE) is subtracted by the amount of VRE charged and consumed in the storage technologies.

Type 4: Demand-side management (DSM)

With shifting times ranging from some minutes to a few days, DSM in the sectors households, industry and TCS competes with alternative flexibility options like batteries and pumped storage power stations [122]. Following [4,46], FederalPlan models DSM as a functional energy storage with limited storage period. The underlying mechanism modelled is load advance [123], i.e. power demand is increased in off-peak times by switching on appliances and processes (negative balancing power). In turn, demand peaks that would have occurred at a later time are reduced by processes not being switched on (positive balancing power). Note that in this configuration, load shedding, i.e. the non-compensation of reduced load, is not explicitly modelled, despite its relevance particularly with regard to industry processes [78,123].

Referring back the load band logic in the FederalPlan model, power demand in a given load band must be covered at every time step by the respective technology. For DSM this means that a load advance measure is initiated for every upcoming time step with power demand (positive residual load). In this case, demand is advanced by "charging" either VRE surpluses, or generation from installed power plants with idle operation in lower load bands. In the latter case, the model accounts for the variable costs, as well as the CO_2 emissions of the generators stepping up their generation. Overall, the model implementation is similar to the equations described in the storage section above, with the difference being that the storage period is constrained by the shifting time, as set in the potential assessment (Section 3.3.3). In addition, load advances are assumed to have a 100% efficiency, i.e. no losses occur in the process (FIGURE 16).

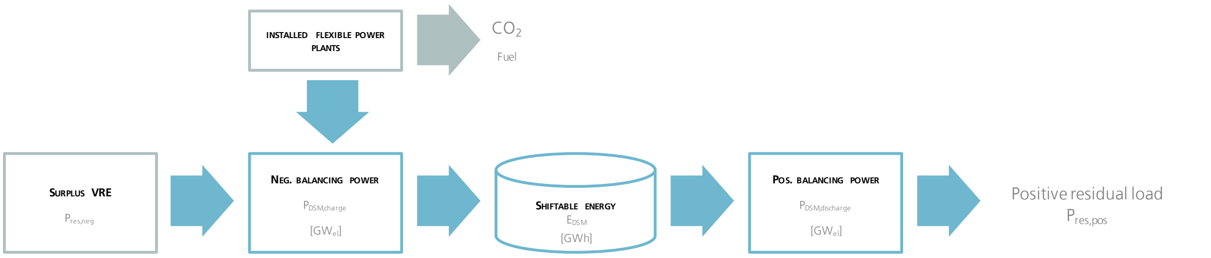


FIGURE 16. Operation principle of DSM in the FederalPlan model. The charging capacity of the functional storage is determined by the negative balancing power, its reservoir capacity by the maximum duration of DSM interventions (shifting time), and its discharging capacity by the positive balancing power. Source: author's own, based on [4].

To limit computational complexity, some practical assumptions were made with regard to the model implementation of DSM:

- DSM interventions can be activated regardless of the typical utilisation periods of single processes and applications. In reality, DSM behaviour of non-residential consumers is directly correlated to industrial production hours and business hours [122].
- DSM interventions are steered via direct load control by utilities, where appropriate. No voluntary load reduction in response to price signals is modelled [2].
- No activation time is considered for DSM interventions, load thus can be reduced or increased immediately in a given time step.

A more detailed linear programming model implementation of DSM on a country-scale is provided by Gils [123], including additional constraints such as outside temperature conditions and limits for DSM interventions for specific processes. Based on [4], costs for DSM implementation are represented in the FederalPlan model by specific investment costs per unit of negative balancing power (exhibiting the ICT infrastructure, personnel, technical co-ordination), as well as annual fixed operation and maintenance costs (reflecting expenditures arising from maintenance and utilisation of the ICT infrastructure) [77,122]. These default parameters are listed in Appendix 7.2, along with the remaining storage technologies.

Type 5: Power-to-heat / Power-to-gas

After the energy consumed by storage and DSM technologies is subtracted from the negative residual load (surplus VRE) available, this power can be utilised by large-scale power-to-heat facilities to provide heat to end users in district heating networks (P2H), or by methanisation facilities to produce natural gas (power-to-gas, P2G). First, P2H can be used if the hourly heat load has not yet been covered by CHP. The underlying operation principle is illustrated in FIGURE 17.

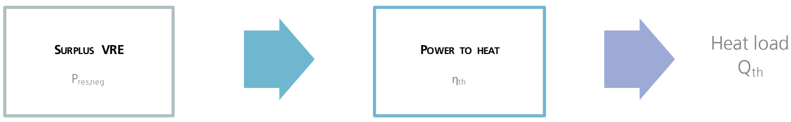


FIGURE 17. Operation principle of Power-to-heat in the FederalPlan model. Source: author's own, based on [4].

The technology option considered for P2H is a large scale electrode boiler, designed to provide heat at demand without interim heat storage [46]. Their possible deployment in the model is based on the following relation: installation of the P2H facility is subject to specific investment costs C_I (in $€/GW_{th}$) and fixed annual operation and maintenance costs $C_{O\&M}$ (in % of the initial investment) (see Appendix 7.2 of the default parameters assumed). The electrode boiler can generate revenue by displacing heat supply from a supposed gas-fired boiler. The latter is characterised by fuel and CO_2 costs. Overall, if the annual revenue of the electrode boiler surpasses its capital and O&M costs, it is deployed in the system. Otherwise, the supposed gas-fired boiler is used to cover the hourly heat load. Subsequently, in case no P2H facilities are deployed due to absence of cost recovery, power-to-gas facilities can be deployed if their annual revenue from displacing natural gas in the gas grid is surpassing the annual capital and operational costs of the methanisation facility. In Appendix 7.2, the default technology assumptions for both P2H and P2G facilities are compiled. Ultimately, if there is surplus generation from VRE left after the P2X deployment, this renewable generation is curtailed in the respective hourly time steps.

Overall, the algorithm for cost-based technology assignment introduced in this section can be considered a reduced-form optimisation [46]. Given its load-band logic, it does not constitute an optimisation problem accurately minimising total systems costs. Yet, for the sake of clarity, its mathematical formulation is provided here:

$$\begin{aligned} & min(C_{sys}) \\ & s.t. \\ & \sum_i P_{gen,i,n}(t) = P_{res,pos,n}(t) \end{aligned} \tag{49}$$

Total system costs C_{sys} (represented by the LCOE) are minimised subject to the power balance, i.e. positive residual load $P_{res,pos}$ (GW) in a load band n and time step t needs to be covered by the aggregate generation P_{gen} (GW) of all technologies i. Concluding this section, the FederalPlan model takes detailed account location-specific generation from VRE, as well as the multiple of power generators and flexibility options possibly available in future for covering residual load. After having described both the demand-side and supply-side implementation of the model, Appendix 7.3 provides a couple of screenshots of the *Excel*-based model implementation. The following chapter provides a critical reflection on the selected modelling approach.

3.5. Critical reflection on the modelling approach

The objective of the FederalPlan modelling tool is to reflect the major interrelations in German federal state energy systems with regard to essential demand and supply side dynamics. Various simplifications were made in order to keep the model manageable with regard to computation and data needs. The following discussion points highlight these limitations and indicate alternative approaches for a possible implementation in future versions of the modelling tool.

Technical detail

As elaborated in Chapter 3.1**,** especially power plants are subject to multiple operational constraints in the process of dispatch and unit commitment. The FederalPlan model includes a simplified representation of these restrictions by attributing an economic penalty to thermal power plants for every warm and cold start in a given load band. This results in a reduced cost-effectiveness for inflexible power plant types at increasing variability in residual load due to VRE deployment. However, this parametrisation does not account for the issue of actual technical feasibility of the dispatch proposed by the model. In reality, the system might be forced to dispatch flexible generators because baseload technologies cannot ramp up fast enough, or curtail VRE in cases where baseload plants are kept on line to prevent start-up costs at later points in time [2,85]. Considering this limitation, a soft-coupling should be performed to gain additional insights regarding the operation of the power system [3,87]. In this approach, the generation portfolio computed by the FederalPlan model is used as input for a separate production cost model which re-computes the operations of the power system using a high level of technical detail (i.e. including ramp rates, start-up times, minimum load levels and other constraints) [3]. Based on existing research, it can be expected that the FederalPlan model underestimates operational costs of the generation mix and overestimates the level of baseload generation. As a result, system costs as well as the efforts needed to effectively obtain a desired reduction of GHG emissions are likely to be underestimated considerably [85].[51] In addition to the operational aspects, it should be mentioned that the model has limitations with regard to technological coverage. For instance, geothermal energy is omitted due its additional modelling complexity resulting from temporary heat storage aspects [46]. This feature could be added in future model versions.

Spatial detail

The FederalPlan tool uses detailed GIS data to derive regional profiles for generation from wind power and photovoltaics, reflecting a reasonable degree of spatial resolution. A critical issue of the model is its consideration of system boundaries. Currently, the modelling tool considers power imports in a stylised manner, with exogenous parameters setting the amount of power transfers between the federal state under consideration (internal region) and a non-specified external region, representing other federal states and surrounding countries. While this approach enables a low degree of computational complexity, it does not quantify the contribution of spatial shifting as a flexibility option by means of enhanced transmission capacities (Chapter 2.2). Pietzcker et al. [7] point out that the costs for transmission expansion are much smaller than the costs for transforming the generation part of the power system, making enhanced interconnection between federal states a potential no-regret option for smoothing VRE variability. However, other research argues that the smoothing effects of grid interconnections will be limited in case of a similar deployment of VRE across Germany [4,46].[52] Accordingly, this issue should be scrutinised in possible future versions of the FederalPlan tool.

Representation of other VRE-related integration challenges

While the FederalPlan tool focuses on the assessment of flexibility needs, it does not take account of the remaining VRE-related integration challenges set out in Chapter 2.2. Considering the need for transmission capacity, FederalPlan supposes a "copper plate", with no grid restrictions existing between all power generation sources and demand [46]. Accounting for the necessity of additional grid capacity could be approached by using fixed limitations to the power transfers between

[51] For instance, Poncelet et al. [85] compare a system's operational costs between the long-term energy planning model TIMES and the highly-resolved production cost model LUSYM. Their results suggest that TIMES underestimates operational costs by 2.6 EUR/MWh due to its disregard of operational constraints. In a similar research design, Nweke et al. [138] compare two setups in the PLEXOS model: one with operational constraints and one without constraints. Results indicate that the run with operational constraints builds more gas plants and retires more existing coal plants, compared to the run without constraints [2].

[52] The reason is the effect of "dark calm" periods that can occur over periods of two or three weeks under very stable weather conditions with almost no barometric pressure differences throughout the country. When extending the spatial detail in the model to several internal regions, these could hardly reduce the flexibility demand in a particular federal state with their own VRE capacities. Yet, as long as VRE capacities are diverse and unequal among federal states, strong grids help reduce short-term power demand [3,46].

multiple nodes, with the power flows being directly attributed to the direct lines between the source and the demand centre [2,25,48]. A highly sophisticated approach could incorporate Kirchhoff's laws and represent the reality of the electric grid, usually linearized as a DC load flow [25]. Furthermore, operating reserves or ancillary services, including voltage and frequency control, are essential elements for maintaining stability in power systems. The FederalPlan tool does not account for these issues by implicitly assuming distinct flexibility- and load-following capabilities for all power generators as well as perfect information with regard to load and VRE generation forecasts. This risks neglecting the investment implications of ensuring system stability. Implementing operating reserve requirements in the FederalPlan tool would thus allow for increased optimality of the modelling solution and capture additional technical constraints on system operation that are often omitted in long-term energy planning models [3,139].[53]

Representation of capital stock dynamics

The FederalPlan tool examines a single target year and does not explicitly model technology transitions as well as existing and written-off assets in the power sector. Transitions are only implicitly taken into account with regard to future technical parameters and costs, which are based on learning curves and the underlying assumption of certain production volumes [4]. This perspective is commonly referred to as a "greenfield" approach [46,96]. In reality, the power sector is characterised by long-lived capital stocks, which limits the short-term adaptability of the system. Future versions of the FederalPlan tool could include a simple non-exponential vintaging approach to capture these developments. This approach would track the construction year for all existing capacities and decommission them after their technical lifetime, with the cost-based technology assignment algorithm selecting new capacities according to their LCOE. More detail could be added by accounting for early retirement aspects with generation assets being decommissioned if their revenues are lower than the variable costs over a longer period of time [7]. Overall, this could enable a more realistic representation of capital stock dynamics. In spite of these possible improvements, the greenfield approach can be useful for providing guidance in the present. It provides insights on how the power system should be designed today in order to attain desired targets in 2050, preventing stranded assets and lock-in effects. For technologies that are likely to be significant in 2050, a corresponding support of research and development and other policy initiatives at present can help attaining the techno-economic progresses needed in future.

[53] In this regard, Welsch et al. [139] introduce a promising approach of equipping the long-term planning model OSeMOSYS with additional equations for primary and secondary reserve. Their results indicate that neglecting these reserves may underestimate power system costs by 8% compared to a reference model not accounting for these constraints.

Limitations of the algorithm for cost-based technology assignment

The algorithm described in Chapter 3.4 decomposes the hourly positive residual load into a high number of load bands and assigns the most economic generation assets to the load bands in a hierarchical matter under the constraint that load is covered at every time step. In mathematical terms, this approach does not constitute an optimisation problem accurately minimising the total system costs, based on an objective function and constraints formulated as equations and inequalities [46,140]. Certainly, there are more sophisticated numerical optimisation methods with higher accuracy and covering more complex interdependencies, such as the commonly used linear and non-linear programming techniques [24,25]. In practice, these approaches would allow for load bands in the FederalPlan tool being covered by multiple technologies throughout a time series, resulting in different system costs. Another shortcoming of the algorithm is that VRE capacities are set exogenously and hence, they are not included in the optimisation. Instead, the method builds upon the residual load curve and only complementary generation technologies are considered to cover this load [46]. While this feature could be integrated in future model versions, the current setup is useful for investigating the impact of VRE deployment on system costs and the configuration of the remaining generation capacities at low computational demands.

Accounting framework for demand projections

The FederalPlan tool models the demand side of the energy system by providing a detailed image of energy use in the end-use sectors (households, transportation, industry and services), in order to simulate system load, the potential for demand-side management as well as power supply in a subsequent step. However, demand projections in the target year are based on a simple accounting framework, which does not consider the decision-making dynamics of firms, households and other actors in response to changes in fuel prices, technology costs and policies. More elaborate setups of the FederalPlan tool should make use of the diversity of simulation approaches to enhance the level of endogenisation in the demand projections. Promising approaches with low degrees of complexity include technology vintage and capital stock-accounting [21,141] as well as market share algorithms (multinomial logit functions) [21,102], while more sophisticated versions could draw upon system dynamics system dynamics, agent-based simulations, and other advanced techniques [106,142,143]. In addition to this lack of endogenous dynamics, the modelling tool so far does not compute the primary energy demand and corresponding CO_2 emissions for the different demand sectors, but only for power supply. This would have required further modelling of the conversion sector, which was beyond the scope of the present research. However, implementation in future version of the tool should prove to be unproblematic.

3.6. Conclusion: Methodical assets and drawbacks of the modelling approach

This chapter has introduced the general concept and different approaches selected for the development of the novel modelling tool FederalPlan. Constituting a model with reduced complexity, its methodology has distinct limitations and, evidently, the field of energy systems modelling offers more sophisticated approaches covering more complex interdependencies and dynamics. However, two advantages of the FederalPlan modelling tool should be emphasised.

On the one hand, the tool is characterised by a low degree of data needs. Due to the high degree of endogenous parameters, the supply side of the model requires almost no additional data for scenario studies. With regard to the demand side, energy balances are readily available for single federal states to enable a basic calibration of the model. End-use balances and technology shares still need to be derived from Germany-wide sources. However, once available, data can be easily integrated in the modelling tool.

On the other hand, the model has relatively short running times, with the algorithm for cost-based technology assignment providing nearly instantaneous results with regard to cost-optimal configurations of thermal power plants, CHP plants, and P2X facilities. This allows for analysing a large set of parameter variations in a short time, making it useful for ministries, utilities and NGO's on a federal state level to comprehend how changes in parameters and boundary conditions affect the overall system design [46]. However, a drawback to this is that the nested optimisation routine for determining optimal storage charging and storage dimensions requires longer running times, which can sum up to 5 hours for a full run on a standard PC. This problem can be alleviated by only optimising storage dimensions for load bands that are likely to be cost-effective for storage technologies (i.e. excluding base load bands). In addition, future versions of the FederalPlan model should find ways of removing non-linearities from the storage operation code, in order to make the optimisation problem suitable for less time-intensive linear programming techniques. Yet, these running are still lower than the ones in complex large-scale EPMs, typically amounting to several days for one optimisation run [48]. In conclusion, to model appears promising to be applied in an exemplary case study for a single federal state.

4. Results: Application of the modelling tool in a case study

The previous chapter has described the development of the FederalPlan model, designed to investigate the long-term dynamics between flexible power supply and structural changes on the demand side of the energy system at a German federal state level. Considering the various simplifying assumptions applied in the model setup, a key concern is its ability to deliver robust and plausible outputs in long-term scenario analyses. In general, the robustness of every model-based scenario analysis is fraught with uncertainties in two respects. On the one hand, *parameter uncertainties* are a result of the numerical assumptions necessary for the model calculations, resulting in the challenge of establishing specific values for conditions in the far future, such as the price of oil or natural gas. On the other hand, *model uncertainties* point towards the interaction of the parameters in the modelling as well as the consideration and omission of relevant aspects [18,20].

The idea behind the present chapter is to evaluate FederalPlan with regard to its model uncertainties in a comparative case study, while setting aside parameter uncertainties. This is performed by comparing selected outputs of the model to the ones obtained from an established scenario analysis, using the same input parameters.[54] For this purpose, Section 4.1 introduces the BW-Report – a scenario study investigating possible decarbonisation pathways for the federal state of Baden-Württemberg up to the target year 2050. Section 4.2 provides the framework of the comparative assessment, used to check the results from the FederalPlan model against those from the BW-Report. Section 4.3 presents the results of this comparative assessment and discusses drawbacks of the FederalPlan model. Section 4.4 performs sensitivity analyses for four selected input parameters, highlighting to what extent the FederalPlan model yields reasonable responses to parameter variations. Finally, Section 4.5 draws conclusions on the robustness of the FederalPlan modelling outcomes.

4.1. Introduction to the reference case

For the application example of the FederalPlan model, the federal state of Baden-Württemberg is selected. Located in southwestern Germany, it is the country's third-largest state in terms of size and population [52,144]. In 2013, the state's government has passed a climate protection law (Klimaschutzgesetz) [145]. Its essential element is a greenhouse gas emissions reduction target, aiming at a 90% reduction by 2050, relative to emission levels in 1990.

[54] Note that the performance of long-term energy planning models cannot be validated by comparing model results with real world outcomes. For the target year 2050 this would imply the necessity to wait for over 40 years to observe actual outcomes for validation purposes, which negates the model's purpose as a planning tool [7,12].

With particular regard to energy-related emissions, a consortium of research institutes has issued a comprehensive model-based scenario study for Baden-Württemberg, investigating pathways from the base year 2015 until the target year 2050 [50].[55] This study is hereinafter referred to as the *BW-Report*. The authors of the BW-Report examine two scenarios – a business-as-usual case (*BAU2050*), as well as a normative case (*TARGET2050*), investigating the developments necessary in the different energy demand and conversion sectors for reaching the 2050 target. The model-based outcomes of these scenarios with regard to GHG reductions until 2050 are displayed in TABLE 14. Evidently, ambitious developments are necessary in the energy demand and conversion sectors in order to reach the 2050 target [50].

TABLE 14. Overview of sectoral GHG emission reduction developments in the BAU2050 and TARGET2050 scenarios of the BW-Report. Source: [50].

	1990	BAU2050	TARGET2050
Energy-related CO_2 emissions [Mio. t CO_2]			
Households	13.7	4.4	0.2
Trade, commerce, services	7.0	3.6	0.3
Transportation	21.0	14.1	2.5
Industry	10.6	4.5	0.3
Power generation	17.6	9.0	0.3
District heating	2.0	1.9	0.9
Refineries	2.5	1.1	0.4
Energy related CO_2 emissions [Mio. t CO_2-eq.]			
	75.0	39.0	5.0
Non-energy-related greenhouse gas emissions [Mio. t CO_2-eq.]			
Subtotal	14.2	7.3	3.9
Greenhouse gas emissions [Mio. t CO_2-eq]			
Total	89.2	46.3	8.9

In reducing GHG emissions in Baden-Württemberg, the power sector is facing particular challenges. On the one hand, particularly the TARGET2050 scenario involves comprehensive fuel and technology substitutions in the energy demand sectors towards increasing electrification, with especially the transport sector experiencing a distinct shift towards electric vehicle usage. This raises the need for additional generation capacities in the target year, which must effectively must be carbon-neutral to reach the emission reduction necessary in the power sector. On the other hand, Baden-Württemberg's present domestic power supply is dominated by nuclear power, amounting to a share of 48% in gross electricity generation in 2010 [93]. Since nuclear power generation is commonly accounted as climate-neutral, specific CO_2-emissions are considerably lower compared to the German average (223 gCO_2/kWh versus 563 gCO_2/kWh in 2010) [146]. Given the decision of the German government to phase out nuclear power by the end of 2022 [147], Baden-Württemberg must restructure a large share of its power supply over the coming years in order to ensure a low-carbon transition by the year 2050.

[55] The authors use a combination of bottom-up models for the scenario projections. The industry sector is based on the FORECAST model, the transport sector on TREMOD, the household and TCS sector on GEMOD and FORECAST [50]. The power sector follows a generic accounting approach discussed further below.

In spite of these challenges, both scenarios project a comprehensive decarbonisation of power supply in Baden-Württemberg, amounting to a 49% GHG emission reduction in the BAU2050 case, and 98% in the TARGET2050 case [50] (TABLE 14). Note that in the BW-Report, accounting of CO_2 emissions is performed according to the *source principle* (Quellenbilanz). This statistical convention commonly used at a federal state level sums up all emissions from domestic power generation within a federal state, while the emissions associated with power imports are not accounted for [93,108].

These results in the BW-Report for the power sector are based on a model not named by the authors [50], it is thus hereinafter referred to as the *BW-POWER* model. Basically, it builds upon the sectoral developments in electricity demand in the two scenarios and projects the power supply needed to cover this demand, along with its annual CO_2 emissions. In comparison with the FederalPlan model developed in this thesis, the BW-POWER model has different properties, summarised in TABLE 15.

TABLE 15. Qualitative comparison of the models FederalPlan and BW-POWER. Source: author's own.

(model)	**FederalPlan**	**BW-POWER**
General properties		
Modelling logic	Optimisation	Accounting
Temporal detail		
Temporal resolution	Hourly	Yearly
Time intervals	single year ("greenfield" 2050)	10 years
Technical detail		
Technological portfolio	Power plants; CHP; Storage; P2X; DSM	Power plants; CHP; (Storage); P2X
Technical detail (power plants)	Startup/ramping costs	-
Spatial detail		
System boundaries	Single internal region, exogenous imports	Single internal region, exogenous imports
Spatial resolution (VRE)	Regional VRE generation profiles	Regional VRE generation profiles

An essential difference lies in the modelling logic. While FederalPlan performs a cost-based optimisation, BW-POWER model applies an accounting framework to derive capacities installed as well as generator dispatch.[56] With regard to temporal detail, the FederalPlan model features a higher temporal resolution, while the BW-Report applies a higher disaggregation into time intervals. Considering technical detail, both models feature a large technological portfolio. However, the BW-Report does not include storage technologies other than pumped hydro-electric storage. In turn, the FederalPlan does not include waste and geothermal power plants, as well as other generators with minor system relevance. Based on the accounting logic and the yearly resolution, the BW-Report also does not take into account operational constraints and ramping costs. Finally, regarding spatial detail, both models define narrow system boundaries, with Baden-Württemberg being the only internal region considered. Imports are set as exogenous parameters

[56] In this accounting approach, power generator lifetimes are tracked starting from the base year 2015. In case a generator reaches the end of its lifetime, it is decommissioned and replaced, based on narrative exogenous assumptions. For example, in the TARGET2050 scenario, the authors presume a gradual phase-out of hard coal-capacities in Baden-Württemberg by 2045, which is replaced by gas-fired power plants. Annual electricity generation is based on fixed full load hours and efficiencies per generator type, yielding the amount of CO_2 emissions [50].

in both cases, exports are not taken into account. Regarding spatial resolution, both models use regional data to derive the electricity yield from VRE generators.

Considering the features of FederalPlan and the BW-Report-POWER model, a comparative assessment of their modelling outcomes is likely to yield differences with regard to the long-term dynamics of power supply in response to structural changes in sectoral energy demand. For a systematic analysis of these differences, the following section describes the methodical framework of the comparison.

4.2. Framework of the comparative assessment

The comparative assessment between FederalPlan and the BW-POWER model for the case of Baden-Württemberg in 2050 is centred around three analytical questions:

(1) What mix of VRE generators, reserve power plants, storage facilities and DSM measures is deployed in the target year 2050 to meet electric power demand?
(2) What CO_2 emissions arise from the power supply configurations in the target year?
(3) What relevance is attached to power-to-heat (P2H) and power-to-gas (P2G) facilities for coupling VRE supply to the demand sectors?

As introduced above, the BW-Report features two scenarios – the reference case BAU2050, as well as the normative case TARGET2050. In the following, all results obtained from the FederalPlan model are referred to as *FP-BAU2050* and *FP-TARGET2050*, while all results related to the BW-POWER model are named *BW-BAU2050* and *BW-TARGET2050*, respectively. The procedure of the comparative assessment involves five steps for each scenario, illustrated in FIGURE 18 and described in the following.

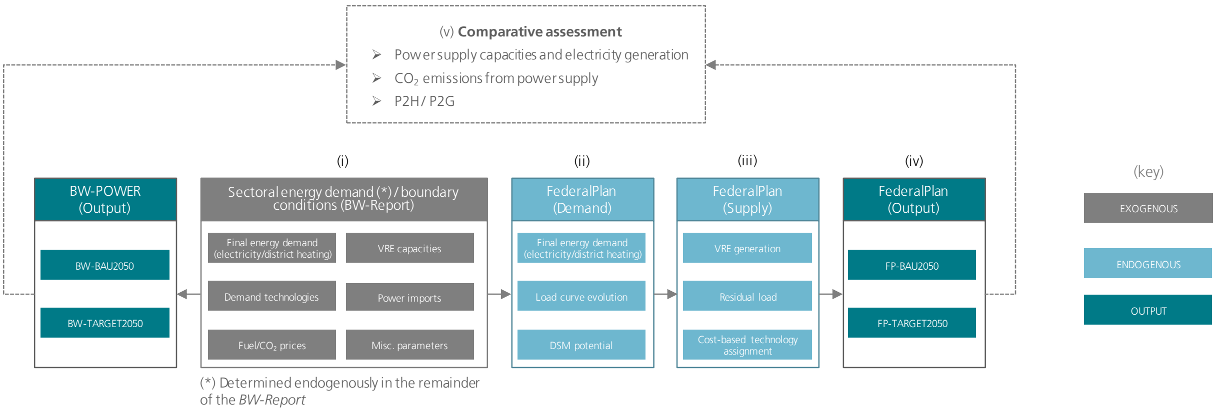


FIGURE 18. Procedure applied for a comparative assessment of power system characteristics between the FederalPlan model and the BW-Report-POWER model. Source: author's own.

(i) The BW-Report is analysed with regard to its projections for sectoral energy demand, with particular emphasis on demand for electricity and district heating. These developments are summarised in TABLE 16 in qualitative terms, while the further analysis requires a more detailed quantitative appraisal, elaborated upon further below. In addition to the sectoral developments, boundary conditions and scenario assumptions relevant for the power sector are derived from the BW-Report, including fuel and CO_2 prices, installed VRE capacities, the amount of power imports, as well as miscellaneous parameters.

TABLE 16. Demand sector developments projected in the BW-Report for the scenarios BAU2050 and TARGET2050. Source: [50].

	BAU2050	TARGET2050
Households	• Limited renovation of building stock • Large contribution of fossil fuels to space heating and hot water supply • ongoing use of inefficient appliances and devices	• improved building performance • Replacement of fossil-fired heat generators/night-storage heaters • Replacement of inefficient household appliances and devices
Trade, commerce, services	• (analogous to households sector)	• (analogous to households sector) • Diffusion of efficient lighting technology • Enhanced ventilation and air conditioning systems
Transport	• Large contribution of diesel and gasoline fuels to final energy consumption • Limited electrification of passenger and freight transport	• Shift of motorised private transport to public transport • Electrification of passenger car fleet • Electrification of utility vehicles (trucks)
Industry	• Economic growth drives increase in final energy demand, improvements in energy efficiency insufficient to counteract this effect	• Extensive utilisation of energy efficiency potentials • Structural change towards secondary products and circular economy • Replacement of CO_2-intensive fossil fuels by biomass, natural gas and district heat

Given that some important boundary conditions and scenario assumptions for setting up the FederalPlan model are not available from the BW-Report, alternative data sources are consulted:

- Fuel prices for domestically produced fuels (biomass, biomethane, lignite) are taken from [46,148] for the case of Germany in 2050.
- CO_2 emission factors for the different fuels are taken from [149].
- The annual availability of biomass and biomethane issues from official statistics for Baden-Württemberg [150], the assumption being that annual power generation from these fuels does not increase by 2050 due to competition with food production.
- Costs of power plants, storage facilities and DSM originate from [46] for the case of Germany in 2050, corresponding to the values listed in Chapter 3.4 and Appendix 7.2.
- Note that all cost calculations are based on 2013 prices without consideration of inflation.

Accordingly, all boundary conditions and scenario assumptions relevant for modelling power supply in the FederalPlan model are listed below (TABLE 17):

TABLE 17. Boundary conditions and scenario assumptions used in the models BW-POWER and FederalPlan. EUA = European emission allowance. Source: author's own, based on [50].

Parameter [2050]		BAU2050	TARGET2050
Fuel prices			
Biomass	€/GWh$_{th}$	16,905	
Biomethane	€/GWh$_{th}$	54,090	
Hard coal	€/GWh$_{th}$	14,760	
Lignite	€/GWh$_{th}$	1,500	
Natural gas	€/GWh$_{th}$	36,720	
EUA	€/tCO_2	90.0	
VRE capacities and generation			
PV	GW (TWh/a)	12.16 (11.30)	20.55 (19.10)
Wind	GW (TWh/a)	3.18 (9.20)	9.24 (27.00)
Hydro	GW (TWh/a)	0.89 (4.50)	0.89 (4.50)
Power imports			
Total imports	TWh/a	37.00	34.60
Import costs (LCOE)	€/MWh	79.33	
CO_2 intensity	gCO_2/kWh	81.69	
RES share	%	57.4%	
Miscellaneous parameters			
Line losses	% [rel. to final electricity cons.]	1.8%	1.8%
Refinery losses	% [rel. to final electricity cons.]	0.7%	0.5%
Power plant own consumption losses	% [rel. to final electricity cons.]	2.2%	0.9%
Discount rate	%	4% [57]	
Availability biomass	GWh$_{th}$/a	3,200.00	
Availability biomethane	GWh$_{th}$/a	7,350.00	

(ii) Final energy demand in the FederalPlan model is calibrated to the energy balance of Baden-Württemberg for the base year 2015 [108]. This is done by applying the input data listed in Appendix 7.4. Subsequently, based on step (i), developments in final energy demand (with focus on electricity and district heating) are replicated as closely as possible in the FederalPlan model, e.g. the rise in electricity consumption in response to diffusion of electric vehicles. This step is important for two reasons: On the one hand, it yields the scenario-specific amount of final energy consumption for electricity and district heat, which delivers the essential starting point for running the supply optimisation in FederalPlan. On the other hand, it provides estimates of load curve alterations and DSM potentials, which also affect the optimisation procedure.[58] The various parameters set in the FederalPlan to replicate the developments in final energy demand for each demand sector and scenario are listed in Appendix 7.4. Note that the BW-Report is not always explicit regarding distinct sectoral developments, structural changes and efficiency improvements. For this reason, educated guesses were made for multiple parameters.

(iii) Based on the supply-relevant boundary conditions and scenario assumptions (Step i), and the sectoral developments in energy demand (Step ii), the supply-side of the FederalPlan model

[57] This corresponds to a social discount rate, evaluating total costs and benefits of energy systems from a societal perspective. Chapter 4.4 further elaborates on the choice of the discount rate and its implications for the scenario outcomes.

[58] Note that if load curve alterations and DSM potentials were to be considered irrelevant, the annual consumptions of electricity and district heat could be inserted directly into the supply optimisation module of the FederalPlan model.

computes the generation from VRE and the corresponding residual load. Subsequently, the algorithm for cost-based technology assignment is run.

(iv) The FederalPlan model yields endogenous outputs with regard to the aforementioned questions.

(v) The outputs are compared to the ones obtained from the BW-POWER model in the BW-Report.

Based on the framework introduced here, the following section elaborates on the results of the comparative assessment.

4.3. Results of the comparative assessment

In the following, the results of the comparative assessment between the FederalPlan and the BW-POWER model are described, along with conclusions that can be drawn about the robustness of the FederalPlan model. As stated above, scenarios outcomes are referred to as FP-BAU2050 / FP-TARGET and BW-BAU2050 / BW-TARGET2050, respectively for each model. First, several demand-related outputs of the FederalPlan model are presented. Subsequently, reference is made to the three points of comparison introduced above: (1) Power supply capacities and electricity generation; (2) CO_2 emissions from power supply; (3) Significance of P2H and P2G. Finally, given that the BW-Report does not provide outputs in this regard, the socio-economic costs of future power system configurations are considered based on the FederalPlan model in order to highlights its capabilities in this regard.

Demand-related outputs of the FederalPlan model

The FederalPlan model replicates the sectoral developments in final energy consumption from the BAU2050 and TARGET2050 scenarios. FIGURE 19 illustrates these developments for the TARGET2050 case. As can be seen, final energy consumption reduces in each demand sector, resulting in a total reduction from 1025 PJ (2015) to 627 PJ (2050). In turn, electricity consumption increases from 237 PJ (2015) to 315 PJ (2050). The strong increase in electricity consumption is mainly due to the distinct penetration of heat pumps in the household and TCS sector, as well as the diffusion of electric vehicles in the transport sector (see also Appendix 7.4). In the BAU2050 scenario (not shown in the Figure), final energy consumption decreases to from 1025 to 825 PJ, with electricity consumption rising from 262 to 275 TJ in 2050.

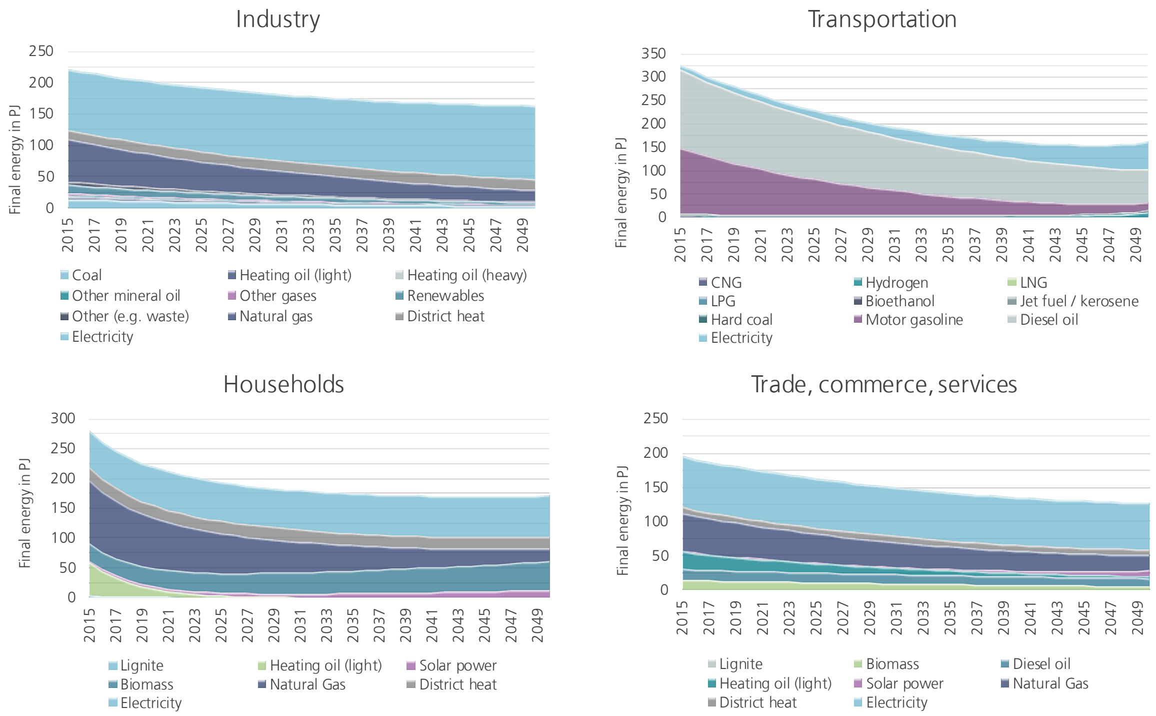


FIGURE 19. Sectoral final energy consumption in the TARGET2050 scenario. Replication of the results from the BW-Report in the FederalPlan model. Years between base year (2015) and target year (2050) are interpolated logarithmically. Source: author's own.

Based on the technology mix in the demand sectors in the target year, the FederalPlan model endogenously projects the hourly load curve for the BAU2050 and TARGET2050 scenarios. FIGURE 20 illustrates the normalised load curves for a selected week in 2050, compared to the base year 2015. It is apparent that the curve in TARGET2050 differs more from the initial curve than the one projected in BAU2050. This relates to the more distinct structural changes in the former scenario, including technology and fuel substitution (e.g. heat pumps replacing other heat generators), diffusion of energy efficient technologies (e.g. household appliances), and macro-economic impacts (e.g. changes in sectoral activity in the industry).

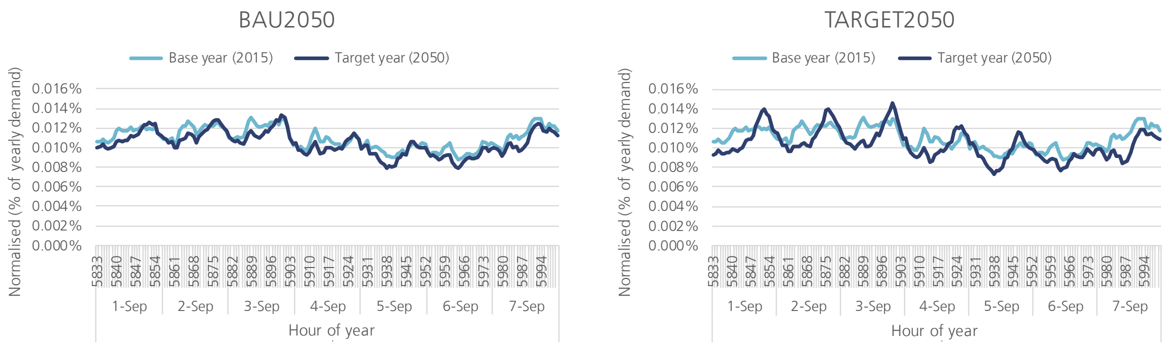


FIGURE 20. Load curve projections from the FederalPlan model for the BAU2050 and TARGET2050 scenarios, as well as the base year 2015. Profiles are normalised to annual consumption, representing a week in September. Source: author's own.

In order to assess these load curve alterations in quantitative terms, a range of indicators is used (TABLE 18). Gross electricity consumption equals 79.9 TWh in BAU2050, with load ranging between 2.96 and 15.03 GW. In TARGET2050, demand is much higher (90.3 TWh), along with a greater need for peak capacity (18.15 GW). The capacity factor is an indicator for the average usage (and hence the profitability) of the overall installed power generators [95]. Here, a clear decrease is recognisable when considering the base year (63.0%), BAU2050 (60.8%), and TARGET2050 (56.8%). Considering the requirements for peak load capacity in more detail, the mean duration and total number of hours with maximum load are useful indicators. The 1.5 GW of capacity in BAU2050 which meets the top ten percent of load is expected to run for an average of 3 hours per plant start, and for a total of 109 hours per year. In TARGET2050, peak loads are shorter and more pronounced, with the top ten percent only running for 39 hours per year, in blocks of 2.22 h per start. Power plants in TARGET2050 must therefore recover their fixed costs from fewer running hours, which in reality gives rise to higher price spikes during peak times [95]. In order to evaluate the effect of the load curve projection on the power supply-related outputs of the FederalPlan model, Chapter 4.4 includes a sensitivity analysis.

TABLE 18. Quantitative indicators for load curves projected in the FederalPlan model. Source: author's own, based on [95,118].

Parameter	Symbol	Unit	[2015]	FP-BAU2050	FP-TARGET2050
Gross electricity cons.	D	TWh	71.8	79.9	90.3
Min. load	min(L)	GW	3.54	2.96	3.26
Max. load	max(L)	GW	13.00	15.03	18.15
Capacity factor	mean(L)/max(L)	%	63.0%	60.8%	56.8%
Mean duration of max. load	mean(Δ90%-100%)	h	2.71	3.03	2.22
Total number of hours with max. load	∑(Δ90%-100%)	h	65	109	39
Mean ramp rate	mean(rr)	GW/h	0.26	0.29	0.38

Subsequently the FederalPlan model computes the practical DSM potential in the demand sectors, i.e. all consumer facilities and devices that can be controlled by ICT infrastructure and that are subject to sufficient acceptance for load interventions. According to the parameters introduced in Chapter 3.3.3, an average acceptance factors of 0.8 and 1.0 are set for the household and tertiary sector, respectively, indicating that the consumer acceptance for DSM interventions is high in 2050. In addition, all processes and appliances are aligned to a common shifting time (τ) of 6 hours with proportionally reduced power. The practical potentials in terms of positive and negative balancing power are listed for both scenarios in TABLE 19. It is apparent that the overall potential in TARGET2050 is more than twice as high as in the BAU2050 scenario, mostly owing to the greater diffusion of plug-in electric vehicles which provide their batteries for DSM. The differences in the industry and TCS sectors are less distinct, relating to efficiency improvements and electrification of processes.

TABLE 19. Practical DSM potential determined in the FederalPlan model for the BAU2050 and TARGET2050 scenarios. The provision period is set to 6 hours. Source: author's own.

Parameter	Unit	Industry	Households	TCS	Total
BAU2050					
Pos. balancing power	GW	0.07	1.14	0.02	1.23
Neg. balancing power	GW	0.01	1.16	0.07	1.23
TARGET2050					
Pos. balancing power	GW	0.09	3.57	0.02	3.69
Neg. balancing power	GW	0.01	3.58	0.09	3.68

Overall, these potentials are likely to underestimate the practical DSM potential in 2050. Due to the methodical issues mentioned in Chapter 3.3.3, appliances and processes running as a function of outside temperature (most notably heat pumps) are neglected in the analysis. Furthermore, batteries coupled to PV systems in private households are not considered, despite their importance suggested in literature [46,112].

In a next step, the FederalPlan computes gross residual load for the BAU2050 and TARGET2050 scenarios, i.e. the difference between system load and the generation from variable renewable energy generators, excluding imports (see Chapter 3.4.1). FIGURE 21 illustrates the gross residual load as duration curves for both scenarios. As stated in the load curve section, the peak load that needs to be covered by power generators amounts to 15.0 GW in BAU2050 and 18.2 GW in TARGET2050. The generation profiles of VRE appear to coincide with these peaks, reducing it to 13.3 GW (BAU2050) and 14.6 GW (TARGET2050). In total, given the contribution of VRE generation, gross electricity consumption reduces from 80 TWh to 55.7 TWh (69.6% VRE coverage) in BAU2050, and from 90.3 TWh to 46.5 TWh (51.5% VRE coverage) in TARGET2050. Another noticeable difference between the two scenarios is the amount of negative residual load, i.e. surplus VRE generation. This surplus amounts to 0.8 TWh in BAU2050 and 6.9 TWh in TARGET2050.

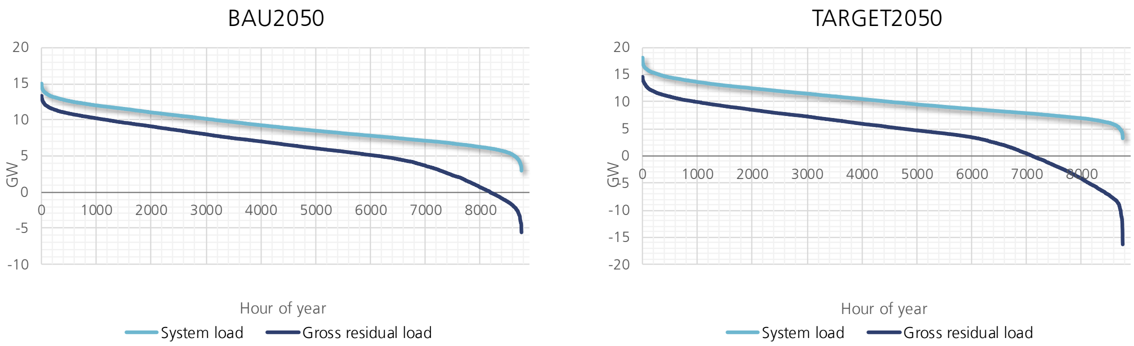


FIGURE 21. Duration curves for system load and gross residual load in the BAU2050 and TARGET2050 scenarios, computed by the FederalPlan model. Source: author's own.

In economic terms, two conclusions can be drawn from this image. On the one hand, the utilisation effect described in Chapter 2.2 appears to be of relevance. While in BAU2050, baseload plants can operate at least 8000 hours per year, this value decreases to about 7000 hours in TARGET2050. Accordingly, capital-intensive baseload generators, requiring a high capacity factor to recoup their fixed costs, are likely to play a minor role in the capacity mix projected by the FederalPlan model for the TARGET2050 scenario. On the other hand, considering the differences in VRE surpluses that are assumed to have zero costs, storage facilities are likely to be less cost-effective technology options in BAU2050 than in TARGET2050.

After having computed gross residual load, FederalPlan models the power imports set in the BW-Report (see Section 4.2) in order to obtain the positive residual load (FIGURE 22). In BAU2050, imports amount to 37.00 TWh per year, in TARGET2050 to 34.60 TWh. Given the hourly resolution of the BW-POWER model, no indication is given as to the maximum load of power imports. For this reason, a constant supply throughout the year is assumed, resulting in a maximum import load of 5.1 GW in BAU2050, and 5.7 GW in TARGET2050. Accordingly, the remaining positive residual load must be covered by domestic generators and flexibility options within Baden-Württemberg.

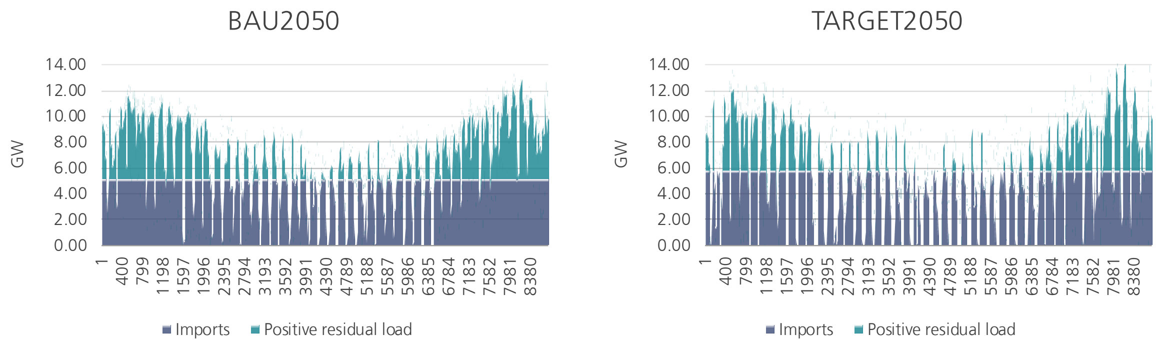


FIGURE 22. Power imports and hourly positive residual load in the BAU2050 and TARGET2050 scenarios, computed by the FederalPlan model. Source: author's own.

In the following, the first issue of the comparative assessment between FederalPlan and BW-POWER is analysed.

Comparison (1): Power supply capacities and electricity generation

FederalPlan and BW-POWER are compared with regard to the amount of reserve power projected, i.e. all generation excluding the contribution of VRE that is necessary to cover positive residual load at all times. Here, multiple observations can be made. Considering FIGURE 23 A), it appears that the BW-POWER model underestimates the reserve capacity needed to cover residual load. This applies to both the BAU2050 and the TARGET2050 scenario. In the former, FederalPlan projects a total reserve capacity of 8.3 GW, while BW-POWER only presumes 7.3 GW (-11%). In the latter case, the deviation is even greater, with FederalPlan assuming 8.9 GW and BW-POWER 5.2 GW (-42%). These discrepancies can be attributed to the yearly resolution applied in BW-POWER, which contrasts with the hourly resolution in the FederalPlan model and its consideration of possible load curve alterations. Accordingly, FederalPlan takes more explicit account of temporal mismatches between VRE generation and power demand. Research highlights the occurrence of so-called "dark calm periods", i.e. time frames of up to several weeks with low output from wind power and PV, raising the need for additional power plants or long-term energy storage units only running a few hours per year [46]. These periods are discernible in the hourly resolution of the FederalPlan model when considering the amount of positive residual load in Figure 22, particularly in the month of December. Overall, in view of these characteristics, the projections derived from the BW-POWER model might significantly underestimate the long-term investment implications of VRE deployment and the corresponding need for flexible reserve capacity.

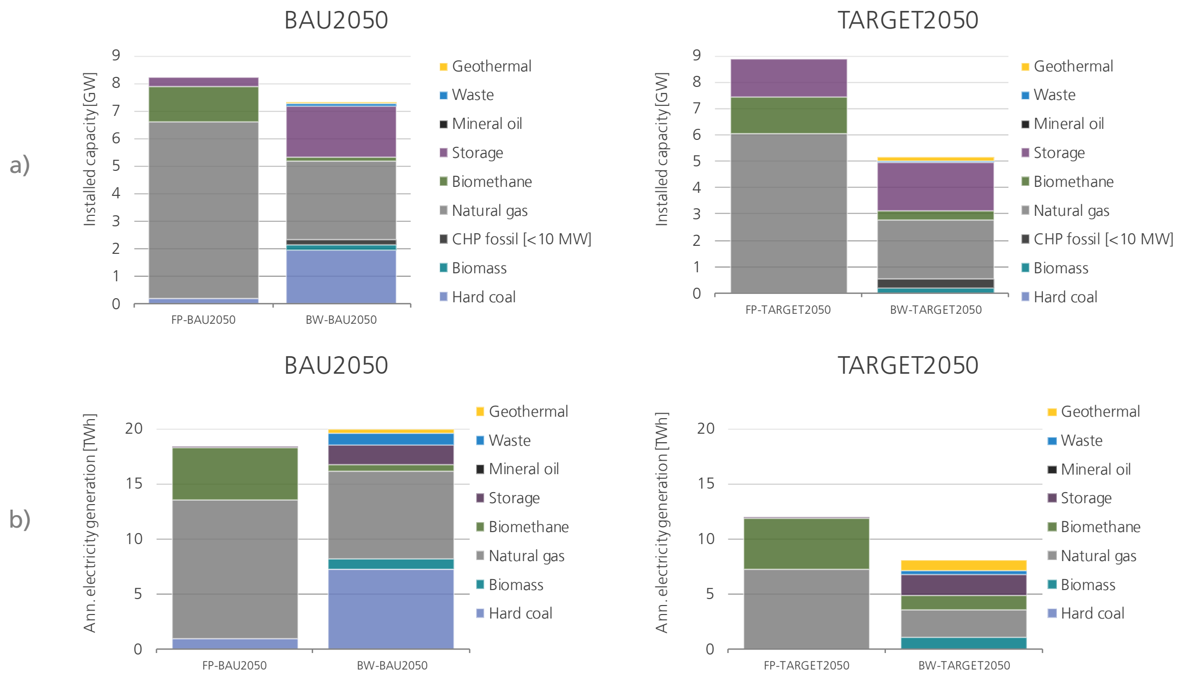


FIGURE 23. Comparison of power reserves (excl. VRE) in the BAU2050 and TARGET2050 scenarios, as projected by FederalPlan and BW-POWER. a) Installed capacity; b) annual electricity generation. Source: author's own.

Considering FIGURE 23 B), observations can be made regarding the annual amount of electricity generated by these reserve capacities. In the BAU2050 case, it appears that regardless of the occurrence of load peaks, FederalPlan expects a better matching of VRE generation and power demand throughout the year than assumed in the BW-POWER model. Reserve capacities only need to generate 18.2 TWh per year in the former case, while in the latter it is 19.9 TWh (+10%). However, considering the TARGET2050 case, reserve capacities need to provide generation to a greater extent (11.9 TWh) than projected by BW-POWER with (8.1 TWh, -32%). Note that both models take no account of additional generation for providing power exports, i.e. the values indicated here are only the ones needed for covering domestic demand (positive residual load). Overall, it appears that the hourly resolution applied by a model has a distinct influence on the projected extent of reserve capacity needed to cover power demand. Taking a more detailed look at the technology mix projected by FederalPlan and BW-POWER, various similarities and differences are discernible – see also TABLE 20 for a quantitative comparison across all scenarios and models, including the base year 2015.

TABLE 20. Installed power capacity and annual electricity generation per technology in the base year, as well as BAU2050 and TARGET2050 from the models FederalPlan and BW-POWER. Source: author's own.

	Base [2015]	FP-BAU2050	BW-BAU2050	FP-TARGET2050	BW-TARGET2050
Generation capacity [GW_{el}]					
PV	5.17	12.16	12.16	20.55	20.55
Wind	0.70	3.18	3.18	9.24	9.24
Hydro	0.88	0.89	0.89	0.89	0.89
Nuclear	2.71	-	-	-	-
Lignite	-	-	-	-	-
Hard coal	5.03	0.16	1.94	-	-
Natural gas	1.04	6.42	2.88	6.04	2.24
Mineral oil	0.28	-	-	-	-
Waste	0.10	-	0.10	-	0.03
Biomass	0.21	-	0.19	-	0.20
Biomethane	0.34	1.32	0.11	1.42	0.34
Geothermal	-	-	0.05	0.00	0.15
Storage	1.87	0.33	1.87	1.42	1.87
CHP fossil [<10 MW]	0.68	-	0.18	-	0.32
Total	19.01	24.46	23.55	39.56	35.83
Electricity generated [TWh/a]					
PV	5.00	11.30	11.30	19.10	19.10
Wind	0.80	9.29	9.20	27.00	27.00
Hydro	4.30	4.50	4.50	4.50	4.50
Nuclear	21.30	-	-	-	-
Lignite	-	-	-	-	-
Hard coal	17.90	0.98	7.20	-	-
Natural gas	3.50	12.56	7.90	7.23	2.50
Mineral oil	0.50	-	-	-	-
Waste	1.00	-	1.10	-	0.40
Biomass	1.10	-	1.00	-	1.00
Biomethane	2.80	4.70	0.60	4.66	1.40
Geothermal	-	-	0.30	-	1.00
Storage	1.80	<0.00	1.80	0.02	1.80
Total	60.00	43.33	44.90	62.52	58.70

First, considering the BAU2050 case, BW-POWER projects a large capacity of hard coal-fired power plants and CHP units (1.94 GW), while FederalPlan indicates a limited capacity of hard coal CHP (0.16 GW). This contrast can be attributed to several factors. On the one hand, BW-POWER follows a narrative accounting approach, stating that hard coal capacities installed in the past are not decommissioned before the end of their 50 year lifetime, leaving the remainder in 2050 [50]. In contrast, FederalPlan applies a cost-based optimisation for a single target year on a "greenfield". Considering the high CO_2 price set across all scenarios (90 €/tCO_2), hard coal generation is barely deployed in the system. On the other hand, the FederalPlan model takes explicit account of the utilisation effect, i.e. reduced cost-effectiveness of baseload generators at high VRE penetrations. The coal capacity installed in FederalPlan TARGET2050 is found to have a capacity factor of only 67.9%, leading to strong competition with less capital-intensive combined-cycle power plants in terms of the levelised cost of electricity. Since the BW-POWER model does not consider cost-optimal system configurations for the target year, this reduced utilisation is neglected, possibly implying a lack of cost recovery for the large coal capacities projected in 2050.

Second, regarding both the BAU2050 and TARGET2050 cases, differences exist with regard to the deployment of biomethane and biomass generators. In the scenarios computed by FederalPlan (FP-BAU2050 and FP-TARGET2050), the full biomethane potential for Baden-Württemberg (7,350 GWh_{th}/a, see Section 4.2) is exploited. This is incentivised by the high CO_2 price, making biomethane-fired combined cycle (CCGT) and open-cycle gas turbines (OCGT) more cost-effective than their natural gas-fired counterparts. However, biomass plants are deployed in none of the FederalPlan cases, which can be attributed to the technology's high investment costs assumed in the model, resulting in high annuity costs and thus a LCOE not competitive with other technology options (see the technology costs in Appendix 7.2). A higher CO_2 price in the model might thus provide greater incentives for biomass deployment. In contrast, considering the cases computed by the BW-POWER model, biomethane capacities and their annual electricity yield are projected to decrease in both scenarios in comparison to the base year 2015. In the narrative approach of the BW-POWER model, this is explained by the end of the German renewable energy tariff for a large share of existing biomethane plants, leading to a net capacity decrease by 2050 [50]. The amount of biomass capacity and generation remains constant in both BW-POWER scenarios, assuming that plants are replaced at the end of their lifetime.

Third, there are distinct differences with regard to the installed capacities and generation from energy storage facilities (TABLE 21). In the scenarios computed by the BW-POWER model, no consideration is given to storage options other than pumped hydro-electric storage (PHES). The assumption being made is that PHES capacities existing in the base year 2015 (1.87 GW_{el}) are maintained until the target year, yielding a constant generation of about 1.8 TWh per year, corresponding to values in 2015. In contrast, the FederalPlan model yields more differentiated results. Considering the TARGET2050 scenario, it is apparent that a large capacity of methane storage is deployed (1.07 GW), in the configuration of re-conversion into electricity be means of an open-cycle gas turbine (OCGT). Methane storage is characterised by high specific investment costs for the charging unit (electrolysis and methanisation), while specific costs for the storage unit are low compared to other storage options, given that the gas can be fed into existing gas storage tanks as well as the gas grid. Given these properties, the technology is commonly mentioned as being suitable for long-term storage of VRE surpluses [4,151]. This is indeed the case computed by the FederalPlan model, as displayed in FIGURE 24 for a time series obtained from the model. The left chart shows how surpluses from PV generation are charged to a small extent during five days in October 2050, indicated by the negative purple bars at the bottom in the range of -0.05 GW. In turn, the right chart displays how cumulated surpluses charged are utilised for peak shaving during three days in December of the same year, releasing an amount of energy around 4.35 GWh. The shifting period between storage charging and re-conversion into electricity thus spans several weeks. Here, the question arises why not more of the pronounced PV surpluses are utilised by long-term methane storage technologies. One explanation is that more charging requires a greater charging capacity, which is associated with considerably greater investment costs, making conventional generators more cost-effective for positive residual load in winter peaks.[59]

TABLE 21. Installed discharging capacity and electricity generation from storage and DSM applications in the base year, as well as the scenarios BAU2050 and TARGET2050. PHES: pumped hydro-electric storage; CAES: adiabatic compressed air energy storage; OCGT: open-cycle gas turbine; CCGT: combined-cycle gas turbine; DSM: demand-side-management. Source: author's own.

	Base [2015]	FP-BAU2050	BW-BAU2050	FP-TARGET2050	BW-TARGET2050
Discharging capacity [GW_{el}]					
PHES	1.87	-	1.87	-	1.87
CAES	-	-	-	-	-
Hydrogen	-	-	-	-	-
Methane (OCGT)	-	-	-	1.07	-
Methane (CCGT)	-	-	-	-	-
Battery	-	-	-	-	-
DSM	-	0.33	-	0.36	-
Total	1.87	0.33	1.87	1.42	1.87
Electricity generated [GWh/a]					
PHES	1,800.00	-	1,800.00	-	1,800.00
CAES	-	-	-	-	-
Hydrogen	-	-	-	-	-
Methane (OCGT)	-	-	-	20.00	-
Methane (CCGT)	-	-	-	-	-
Battery	-	-	-	-	-
DSM	-	0.50	-	0.53	-
Total	1,800.00	0.50	1,800.00	20.53	1,800.00

Another question is the absence of storage options designed for short-term storage in the TARGET2050 scenario computed by the FederalPlan model, including PHES and batteries. Here, the modelling approach developed reveals two weaknesses. On the one hand, the hourly operation of storage facilities is lacking sophistication with regard to charging and discharging behaviour. In reality, PHES plants shift electricity to gain from arbitrage, i.e. the spread between peak and off-peak electricity prices, occurring on a daily or weekly scale [153]. In contrast, the FederalPlan features only a simplified image of arbitrage, with storage plants being able to charge electricity at the yearly average variable costs of the power plant mix below the current load band. This approach neglects the price differentials at single hourly time steps. This issue is compounded by the lack of technical detail in the FederalPlan model with regard to operational constraints of thermal power plants. While in reality especially steam turbine and combined-cycle power plants have minimum load levels once running, the FederalPlan model assumes full flexibility, i.e. instantaneous shutdowns in case of no load to be covered. Given this simplification, power plants in the model do not generate surpluses that could be charged by storage facilities at low or even negative prices.

On the other hand, according to the algorithm for cost-based technology assignment in the FederalPlan model, technologies in a given load band must cover their full power demand throughout the 8760 hours of the year. In other words, one load band cannot be covered by

[59] Methane storage is characterised by particularly high investment costs for the charging unit (electrolysis and methanisation) of 800 million EUR per GWel. Other storage technologies, such as batteries, are considerably cheaper in this regard (45 mEUR/GWel). However, their specific storage costs are also much higher, making them unsuitable for accumulation of VRE surplus for the purpose of long-term storage [152].

multiple technologies. This limits the deployment of storage options designed for short-term shifting. While battery storage might be cost-effective in summer times at diurnal charging and discharging of VRE surpluses, it is hardly suitable for shifting these surpluses over months, due to the large and expensive storage capacity [GWh] needed.

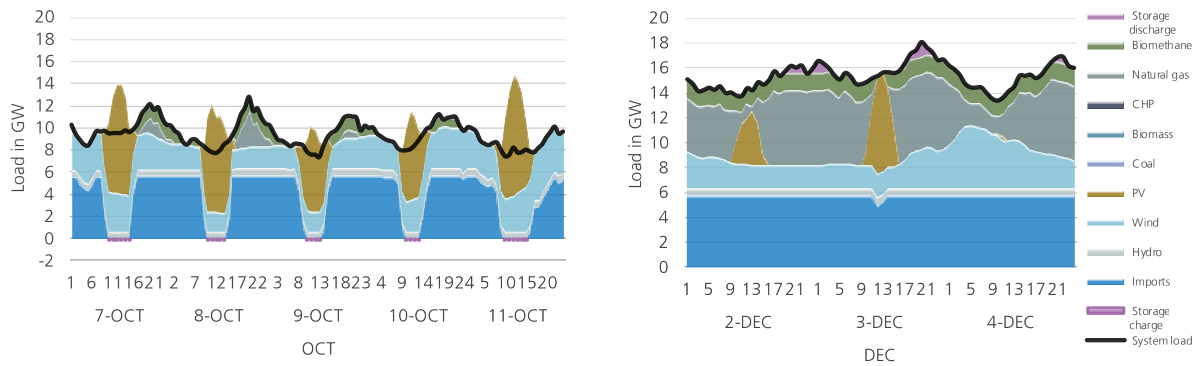


FIGURE 24. Long-term methane storage and re-conversion into electricity in the TARGET2050 scenario, computed by the FederalPlan model (FP-TARGET2050). Source: author's own.

Besides these contrasts in long-term and short-term storage, the consideration of DSM measures contrasts between the PW-POWER and FederalPlan model. While the former does not take account of DSM measures as a flexibility option, the ladder projects a limited utilisation of the potentials determined. In the BAU2050 case, 0.33 GW of positive balancing power is deployed (27% of the practical potential identified), shifting a load of 535.8 MWh per year. In TARGET2050, 0.36 GW of positive balancing power are used (10% of the practical potential), shifting a total of 530.7 TWh. In both cases, DSM potentials are deployed in the two highest load bands, representing the absolute peaks in residual load, only occurring a few hours per year. As an example of utilisation in the model, FIGURE 25 shows a DSM intervention on a December day in the TARGET2050 scenario.

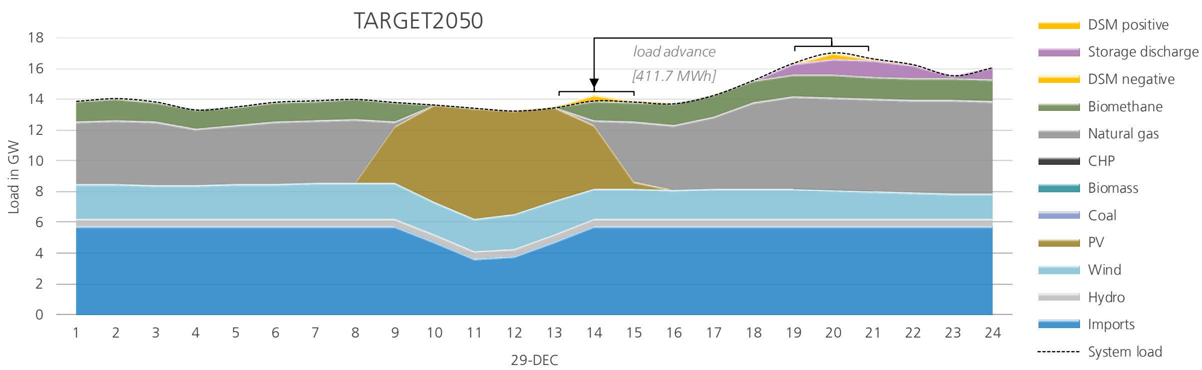


FIGURE 25. DSM load advance intervention in the TARGET2050 scenario as modelled by the FederalPlan model for a day in December 2050. Source: author's own.

In anticipation of the load peak in the hours 19 to 21, a load advance measure is initiated. Off-peak generators in the hours 13 to 15 temporarily increase their generation so that electricity-consuming devices and appliances can be switched on in advance of the initial utilisation time (negative balancing power). Later (hours 19 to 21), the devices and appliances are not utilised anymore, constituting positive balancing power and effectively reducing system load. Note that the shifting time is set to 6 hours, as described above in the potential section. Overall, peak load in the depicted time frame is reduced from 17.02 GW to 16.67 GW (-2.1%), saving additional peak generators necessary for this range.

Similar to the low deployment of storage technologies in the model, here the question arises why the full DSM potentials determined are not exploited. On the one hand, this is again related to the constraint of the algorithm for cost-based technology assignment that a load band needs to be covered in its entirety, i.e. 8760 hours per year. In the case of DSM, it appears that VRE surpluses and backup generators may not always be available to initiate a DSM load advance, violating the coverage constraint and thus preventing DSM from being deployed in certain load bands. On the other hand, the fixed shifting time set for DSM appears to be too inflexible. At present settings, load advance is initiated if there are VRE surpluses or idle generators available 6 hours in advance to the initial consumption time. This fixed setup cannot adjust to situations in which surpluses are only available 4 hours in advance, for instance. In consequence, while this aggregation performed in FederalPlan helps aggregate the total DSM potential to a single metric and hence reduces computational complexity, it neglects the shifting and possible advance times of individual processes and appliances, as highlighted in more sophisticated DSM modelling approaches [122,123].

Comparison (2): CO_2 emission from power supply

Based on the mix of power plants, CHP, storage and DSM utilisation, the FederalPlan model computes annual CO_2 emissions from power generation for the scenarios BAU2050 and TARGET2050. These values are related to those obtained from the BW-POWER model. As mentioned in Chapter 4.1, accounting of CO_2 emissions in the BW-Report is performed according to the source principle, i.e. only including generation within the federal state borders and excluding emissions arising from power imports [50]. FIGURE 26 displays the computed reductions for each scenario and model. Note that the FederalPlan only computes the target year 2050, the intermediate time steps are interpolated between 2015 and 2050 for illustrative purposes.

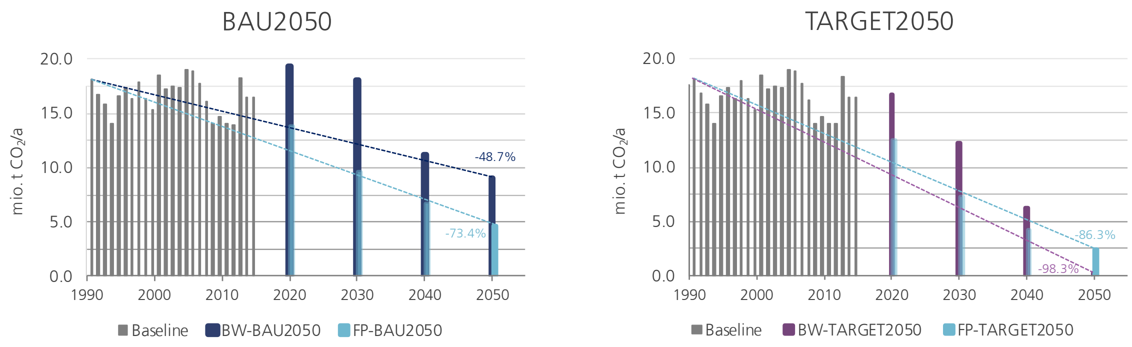


FIGURE 26. Development of CO_2 emissions from power generation in the BAU2050 and TARGET2050 scenarios and indication of reductions relative to the base year 1990. Values for the timespan 2020-2040 are interpolated logarithmically for the FederalPlan (FP) cases. Source: author's own.

In the BAU2050 case, FederalPlan suggests annual emissions of 4.66 mill. tCO_2 for the target year 2050, corresponding to a 73.4% reduction relative to 1990 levels (FP-BAU2050). In contrast, BW-POWER presumes 9.00 mill. tCO_2 in 2050, reflecting only a 48.7% reduction compared to 1990 (BW-BAU2050). This contrast can be attributed to the aforementioned difference in the power generation mix computed by the two models. While in the FP-BAU2050 case the high CO_2 price of 90 €/tCO_2 incites a distinct deployment of biomethane, the BW-BAU2050 case anticipates a large share of incumbent hard coal capacities in 2050. Considering the TARGET2050 scenario, FederalPlan computes annual emissions of 2.41 mill. tCO_2, i.e. a 86.3% reduction by 1990 (FP-TARGET2050). In turn, annual emissions are 0.30 mill. tCO_2 in the BW-POWER model, constituting a 98.3% reduction relative to 1990 (BW-TARGET2050). This corresponds to the fact that FederalPlan projects a large share of fossil natural gas in the target year, while BW-POWER suggests significant contributions of carbon-neutral biomass and geothermal energy. Several conclusions can be drawn from these differences.

First, it appears that the technology portfolio in the FederalPlan model is too limited to represent scenarios with ambitious CO_2 reductions by 2050, such as TARGET2050. This particularly concerns geothermal and renewable waste power plants that make small, yet important contributions to electricity generation in the case computed by the BW-POWER model (BW-TARGET2050) – see also FIGURE 23 above. In addition, biomass should be included in a CHP configuration [46]. Taking these technologies into account in the FederalPlan model would potentially align its CO_2 reduction outcomes to those of the BW-POWER model, in case these technologies turn out to be more cost-effective than their fossil counterparts. Second, modelling outcomes seem to depend strongly on the consideration of transition processes and capital lock-in effects. While the BW-POWER model applies a narrative approach, tracking the lifetimes of generation assets from the base year on, the FederalPlan uses a greenfield approach, with components being built in 2050 with consideration of transition processes only via the cost parameters assumed and associated technology learning. Accordingly, BW-POWER takes account of long-term assets, such as 1.7 GW of hard coal capacity commissioned in 2016 in Baden-Württemberg and its assumed 50 year lifetime [50]. However, BW-POWER does not evaluate to what extent these assets are still profitable in 2050, possibly being overly optimistic about continuous plant operation and cost developments in response to future boundary conditions, particularly the CO_2 price. Third, considering the TARGET2050 scenario in the FederalPlan model (FP-TARGET2050), policy implications can be derived with regard to decisions needed today to reach targets in 2050. Being crucial for a nearly decarbonised power supply in 2050, especially biomass is not deployed in the FP-TARGET2050 case, owing to its high capital and fuel costs. Accordingly, policy makers in Baden-Württemberg could be advised to strengthen research and development efforts with regard to biomass plants in order to reduce its specific investment costs. In addition, loosening the restrictions for power generation from biomass could reduce its specific fuel costs by increasing the supply.

Comparison (3): P2H and P2G

A third benchmark is the deployment of power-to-heat (P2H) and power-to-gas (P2G) facilities. Note that P2H in FederalPlan is understood as large-scale electrode boilers, providing heat to district heating networks (see Chapter 3.4.2). P2G has already been considered in the power supply section as a power-gas-power reconversion configuration. In the case analysed here, electrolysis and methanisation facilities are modelled that provide methane to existing natural gas networks, without explicit consideration of further utilisation as a fuel for production of synthetic fuels in the transport sector.

As for P2H, the BW-Report sets gross consumption of district heat (i.e. taking into account transmission losses) to 13,687 GWh_{th} and 15,220 GWh_{th} in BAU2050 and TARGET2050, respectively. Both models (FederalPlan and BW-POWER) thus compute supply for the same consumption values. FIGURE 27 A) illustrates the hourly coverage of district heating load (GW_{th}) in the household and tertiary sector, as computed by the FederalPlan model. As can be seen, the coal-fired steam turbine CHP deployed in BAU2050 covers a stable baseload of heat demand. However, this contribution only amounts to 13.9% of total district heating demand in these sectors, with the remainder being covered by auxiliary gas boilers (83.4%) and a power-to-heat (P2H) electrode boiler (2.7%). In TARGET2050, no CHP is deployed. Here, gas boilers cover 87.9% of the demand, while P2H makes a greater contribution (12.1%) than in the other scenario, especially during summer times where VRE surpluses are high.

FIGURE 27 B) relates these numbers to the ones from the BW-POWER model. In addition to the previous ones, these numbers also take into account process- and district heat generation for the industry sector. In the BAU2050 case, FederalPlan estimates the contribution of hard coal-fired CHP and P2H reasonably well (FP-BAU2050). However, the share of natural gas in total heat generated is clearly overestimated in comparison to BW-BAU2050. This is because the technology portfolio in the FederalPlan model does not include district heat generators other than coal- and gas-CHP (in OCGT and CCGT configurations), gas boilers, as well as P2H electrode boilers. In the TARGET2050 case, the FederalPlan model appears to overestimate the share of P2H in total heat generated. This relates to the large amount of VRE surpluses computed in the model, which are barely utilised by storage facilities and therefore available for P2H purposes. In conclusion, FederalPlan seems to provide a reasonable image of heat and power supply dynamics. However, the model should be equipped with a more comprehensive technology portfolio in order to provide more detail on future district heating supply configurations.

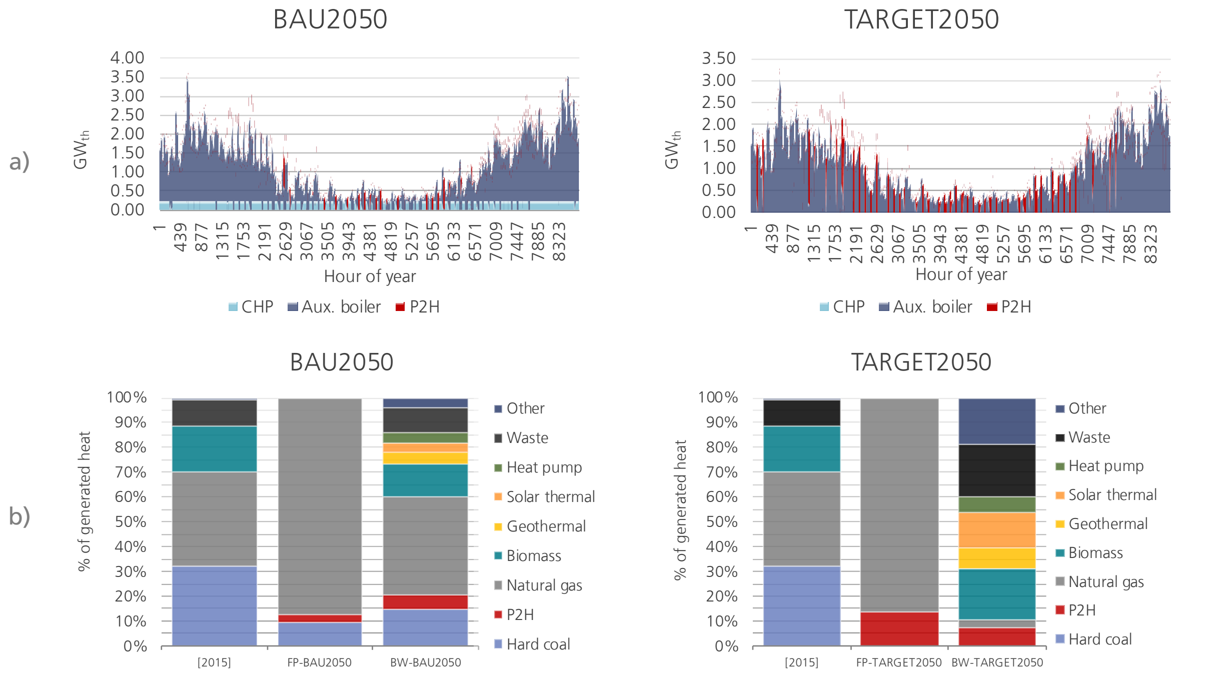


FIGURE 27. Technology shares in district heating supply in the BAU2050 and TARGET2050 scenarios. a) Coverage of hourly heat load in the residential and tertiary sector, as modelled by FederalPlan. b) Technology shares in total district heating demand (incl. industry), as modelled by FederalPlan and BW-POWER. 'Other' includes industrial waste heat, renewable energy methane, sewage gas and landfill gas. Source: author's own.

Considering power-to-gas utilisation, the comparative assessment yields more ambivalent results. The BW-Report makes a stylised attempt of quantifying the needs for synthetic methane in the demand and conversion sectors, as well as for synthetic fuels in the transport sector, in order to attain the federal state's overall CO_2 reduction target (TARGET2050).[60] However, the report does not quantify how these fuels are produced and to what extent VRE generators in Baden-Württemberg contribute to these needs. In turn, FederalPlan endogenously determines installed capacities of electrolysis/methanisation (P2G) facilities by comparing its annuity and annual O&M costs to the revenue from displacing natural gas (see Chapter 3.4.2). Yet, there is no deployment in both BAU2050 and TARGET2050, despite VRE surpluses. This is due to the technology and cost parameters assumed in the model (66% efficiency, 800 m €/GW, 2.5% annual O&M), see also

[60] The report states that in 2050, 60% of fossil fuels in the transport sector would need to be replaced by RE-based synthetic fuels (51.2 PJ/a). In turn, 80% of natural gas consumption in all sectors would need to be substituted by RE-based methane (54.4 PJ/a) [50].

Appendix 7.2. In TARGET2050, deployment only occurs in the FederalPlan model under either one of two conditions (ceteris paribus): First, if specific investment costs decrease by 62.0% to around 300 m €/GW, or second, if the natural gas price rises from 36,720 €/GWh$_{th}$ to at least 97,000 €/GWh$_{th}$, i.e. a 165% increase. In conclusion, the long-term role of power-to-gas and its economic implications remain uncertain, both in FederalPlan and the BW-POWER model.

Cost-related FederalPlan outputs

The socio-economic costs of future power system configurations are not considered in the BW-Report. However, in order to present the capabilities of the FederalPlan model in this regard, a brief overview of cost-related indicators is given for the BAU2050 and TARGET2050 scenarios.

First, TABLE 22 provides the system costs for power supply. Total costs include the annuities, fuel, CO_2, and ramping costs of all generators within Baden-Württemberg plus the costs of power imports. It is apparent that while fuel costs are lower in TARGET2050 due to the higher generation from VRE, annuity costs are greater than in BAU2050. This is mostly associated with the higher electricity demand, resulting in a higher generation capacity needed to cover system load. Total system costs are 6.4% higher in TARGET2050 than in BAU2050, while CO_2 reductions relative to 1990 amount to 86.3% and 73.4%, respectively (see above). Considering the specific costs of electricity, the high share of VRE in TARGET2050 leads to a lower overall LCOE than in BAU2050 (-11.9%), while the specific costs for running reserve power plants are slightly higher (+13%).

TABLE 22. System costs for domestic power supply and total levelised cost of electricity (LCOE) in BAU2050 and TARGET2050, as computed by the FederalPlan model. Source: author's own.

Parameter	Unit	BAU2050	TARGET2050
Total costs	bn. €	5.82	6.19
Annuities	bn. €	1.20	2.32
Fuel costs	bn. €	1.12	0.84
CO_2 costs	bn. €	0.45	0.22
Startup/ramping costs	bn. €	0.09	0.08
Imports	bn. €	2.97	2.74
LCOE (weighted by generation)	€/MWh	77.38	68.15
VRE	€/MWh	48.10	46.28
Power plants	€/MWh	113.66	128.53
Imports	€/MWh	79.33	79.33

Second, the operational dispatch of power generators is considered according to their variable costs – consisting of fuel, CO_2 and startup costs. The FederalPlan model primarily performs long-term investment planning, taking account of full generator costs. In the corresponding algorithm for cost-based technology assignment, generator dispatch is considered on a yearly scale with the most cost-effective generator covering a specific load band throughout the entire year. Based on this, a yearly merit order can be derived, i.e. a ranking of the deployed generators in ascending order of their variable costs [22] (FIGURE 28). Two observations can be made here. On the one hand, the FederalPlan appears to provide a reasonable image of rising variable costs for certain technologies at increasing load. This is because it takes account of startup costs, which increase at higher load bands. If this factor was neglected, the curve would be flat for each technology.[61] On the other hand, the consideration of storage facilities and DSM leads to a dissolution of the merit order at high system load. Storage is subject to variable costs only if it charges power from power plants; charging from VRE surpluses (negative residual load) is assumed to have zero costs. For DSM, variable costs occur for cases of load advance in which power plants need to step up generation to allow for the advance. Accordingly, the variable costs can be very high if the amount of load to be covered in a load band is low and if the energy needed happens to be charged from power plants, see for instance the methane storage peak in TARGET2050.

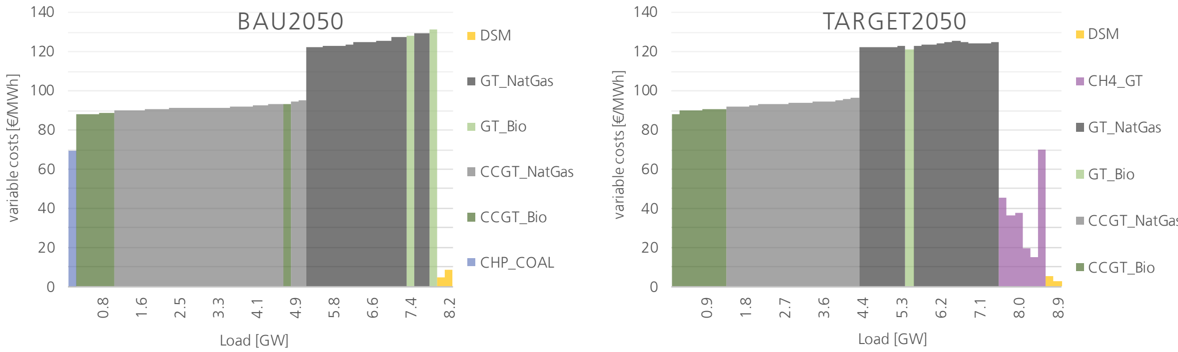


FIGURE 28. Yearly power plant, storage and DSM dispatch (merit order) in BAU2050 and TARGET2050, as computed by the FederalPlan model. GT = gas turbine; CCGT = combined-cycle gas turbine; bio = biomethane; CH4_GT = methane storage with gas turbine reconversion. Source: author's own.

Concluding this section, the FederalPlan provides numerous outputs that appear useful for detailed analyses and case studies. While the comparative assessment with the BW-POWER model has shown a number of differences in outputs, these issues can mostly be attributed to particular characteristics of the two modelling approaches. Especially the contrast between cost-based optimisation on a "greenfield" (FederalPlan) and the long-term narrative accounting of power plant assets (BW-POWER) – i.e. the modelling logic – was argued to have distinct impacts on the outputs obtained. Another example is the implementation of storage operation in FederalPlan, which seems to take insufficient account of arbitrage as a revenue stream for short-term storage types, leading to a limited deployment in the target year despite abundant low-cost VRE surpluses. Following this comparative assessment, the next section further elaborates on the robustness of FederalPlan outputs by performing sensitivity analyses for selected parameters.

4.4. Sensitivity analyses

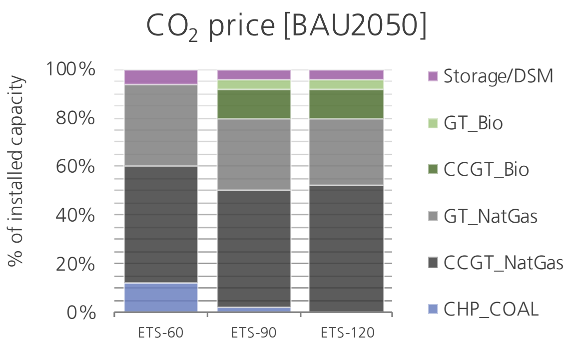
Sensitivity analyses are a common method for assessing the influence of input parameters on model results. This works by varying a single parameter around its normal value, keeping all other parameters unaltered (ceteris paribus). The model outputs of interest are then monitored in

[61] Note that there are small irregularities in the merit order here. The biomethane dispatch in the TARGET2050 case results from its limited primary energy potential, making it unsuitable for covering certain entire load bands. Yet, its variable costs are lower than those of natural gas due to the CO_2 price.

response to these changes [21,154]. Four parameters in the FederalPlan model are selected for this purpose: (i) CO_2 price, (ii) discount rate, (iii) shape of the load curve, (iv) startup costs.

(i) CO_2 price (European Emission Allowance)

The CO_2 price is the centrepiece of the European Union Emission Trading scheme (EU ETS). In the FederalPlan model, an increasing CO_2 price should clearly lead to the deployment of less carbon-intensive power generators. This is evaluated for the BAU2050 scenario. Following the policy analysis carried out by Hübler et al. for the year 2050 [155], CO_2 prices are set to 60, 90 (default in BAU2050), and 120 €/tCO_2. The corresponding results are listed in FIGURE 29, referring to the three options as ETS-60, ETS-90 and ETS-120.



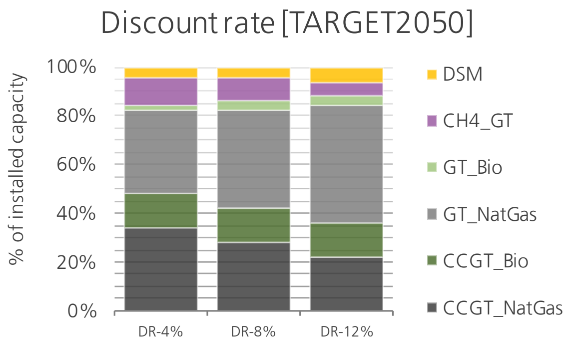
Indicator	Unit	ETS-60	ETS-90*	ETS-120
Total costs	bn. €/a	2.60	2.85	2.99
LCOE	€/MWh	74.53	77.38	79.07
Ann. CO_2	MtCO_2/a	7.93	4.66	4.34
Spec. CO_2	g/kWh	182.99	107.58	100.07
CO_2 reduction [rel. to 1990]	%	54.8%	73.4%	75.3%

FIGURE 29. Sensitivity of selected FederalPlan outputs to the EU-ETS CO_2-price in the BAU2050 scenario. Left: Technology shares in installed reserve capacity (i.e. excl. VRE). Right: Cost- and CO_2-related indicators, all excluding power imports. GT = open-cycle gas turbine; CCGT = combined-cycle gas turbine; CHP = combined heat and power. (*) default parameter in scenario. Source: author's own.

It is apparent that the model is generally sensitive to changes in the CO_2 price, with annual emissions ranging between 7.93 and 4.34 MtCO_2. More specifically, considering reserve capacities, hard-coal fired CHP is largely deployed in the lowest case (ETS-60), then being increasingly replaced by biomethane-fired CCGTs and OCGTs (ETS-90). However, due to the primary energy limit for biomethane, the missing CHP in the last case is replaced by natural gas, still leading to a relative reduction in emissions (ETS-120). Storage and DSM deployment in the model is found to be insensitive to the CO_2 price, given that these facilities need to charge power from whatever thermal generator available in order to cover residual load in their respective load bands. Total costs rise with increasing CO_2 price, which is mostly due to the utilisation of biomethane, having higher specific fuel costs than natural gas and hard coal (see cost parameters in Chapter 4.2).

(ii) Discount rate

The discount rate determines how much to weight costs incurred in the future relative to the present. In the FederalPlan model, it is particularly relevant with regard to the endogenous investment planning, balancing the deployment of capital-intensive and fuel-intensive technologies through the annuity factor [20,21] (see Chapter 3.4). For evaluating the impact of the discount rate on model outputs, the TARGET2050 scenario is used, given its greater deployment of capital-intensive methane storage. By default, the scenario applies a social discount rate of 4%, i.e. assessing costs from a social perspective without consideration of market failures and individual risk [156]. Following [46], two additional model runs are performed with discount rates of 8% and 12%. These correspond to private discount rates from the perspective of individual investors, with the cost of capital being the expected rate of return demanded by investors in common stocks or other securities subject to the same risk as the project [156]. FIGURE 30 shows the results for the three model runs, referred to as DR-4%, DR-8%, and DR-12%.



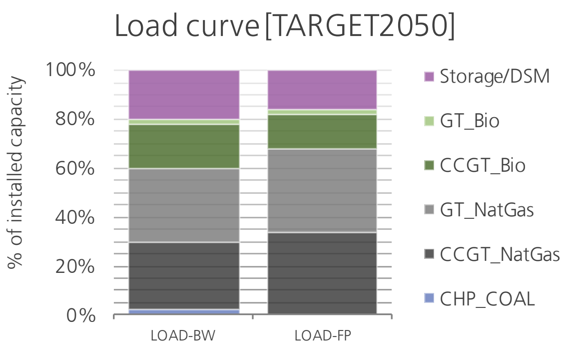
Indicator	Unit	DR-4%*	DR-8%	DR-12%
Total costs	bn. €/a	3.45	4.23	5.10
LCOE	€/MWh	68.15	76.18	85.17
Ann. CO_2	$MtCO_2/a$	2.41	2.48	2.58
Spec. CO_2	g/kWh	38.50	39.68	41.28
CO_2 reduction [rel. to 1990]	%	86.3%	85.9%	85.3%

FIGURE 30. Sensitivity of selected FederalPlan outputs to the discount rate in the TARGET2050 scenario. Left: Technology shares in installed reserve capacity (i.e. excl. VRE). Right: Cost- and CO_2-related indicators, all excluding power imports. GT = open-cycle gas turbine; CCGT = combined-cycle gas turbine; CH4_GT = methane storage with gas turbine reconversion. (*) default parameter in scenario. Source: author's own.

It is found that the deployment of relatively capital-intensive technologies clearly depends on the discount rate used. This concerns particularly natural gas-fired CCGTs, as well as methane storage. While the former decreases from 3.02 to 1.95 GW (-12.0 percent points in total reserve capacity) between DR-4% and DR-12%, the latter decreases from 1.07 to 0.53 GW (-6.0 percent points). In turn, technologies with comparably low specific investment costs are deployed, most notably natural-gas fired gas turbines. The differences in the technology mix go along with slight deviations in CO_2 emissions, e.g. the CO_2 reduction relative to 1990 is 1.0 percent point lower when applying a 12% discount rate instead of 4%. Overall, due to the annuities, total costs rise with increasing discount rate.

(iii) Load curve

The sensitivity of FederalPlan outputs to the shape of the system load curve is evaluated for the TARGET2050 scenario by comparing two setups – one using the default system load curve of Baden-Württemberg in 2015 (LOAD-BW) [121], and one using the curve projected by the FederalPlan model (LOAD-FP). The profiles are normalised, with their integrals yielding the same amount of gross electricity consumption over the yearly timespan. Considering the results (FIGURE 31), two conclusions can be drawn.



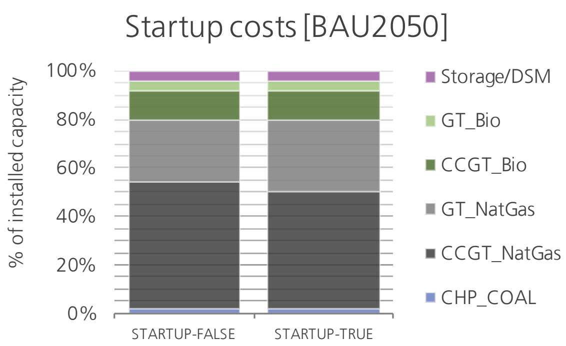
Indicator	Unit	LOAD-BW	LOAD-FP*
Total costs	bn. €/a	2.29	3.45
LCOE	€/MWh	67.08	68.15
Ann. CO_2	$MtCO_2/a$	2.08	2.41
Spec. CO_2	g/kWh	34.19	38.50
CO_2 reduction [rel. to 1990]	%	88.1%	86.3%

FIGURE 31. Sensitivity of selected FederalPlan outputs to the shape of the system load curve in the TARGET2050 scenario. Left: Technology shares in installed reserve capacity (i.e. excl. VRE). Right: Cost- and CO_2-related indicators, all excluding power imports. GT = open-cycle gas turbine; CCGT = combined-cycle gas turbine. (*) default parameter in scenario. Source: author's own.

First, as evaluated quantitatively in Chapter 4.3, the LOAD-BW curve is characterised by a higher capacity factor than LOAD-FP (63.0% versus 56.8%), meaning that the average utilisation of generators is higher in the former case. In fact, when applying LOAD-FP instead of LOAD-BW, the model shows that gas-fired CCGTs are replacing more capital-intensive and baseload-oriented coal-fired steam turbine CHPs. Hence, power plant utilisation and corresponding cost-effectiveness do not only depend on the diffusion of VRE (see Chapters 2.2 and 4.3), but also on the shape of the load curve, which in turn is related to the diffusion of technologies in the demand sectors. Second, despite the replacement of efficient hard-coal-CHP by gas turbines and CCGTs, CO_2 emissions are higher when using LOAD-FP instead of LOAD-BW. This is because of the alignment of VRE supply and power demand. In LOAD-FP, positive residual load amounts to 11.92 TWh, while LOAD-BW it is only 10.30 TWh, indicating a better coverage of load by VRE in the latter case. Accordingly, both system costs and CO_2 emissions are found to be higher when applying the endogenously modelled load curve.

(iv) Startup costs

Thermal power plants and CHP plants in the FederalPlan are subject to specific costs for generator startups, with a distinction being made between cold (>24 hours idle time) and warm starts (<24 hours idle time) (see Chapter 3.4.2). Flexible gas-turbine and engine plants have lower costs than less flexible steam turbine and combined-cycle plants. The effect of these costs are evaluated by comparing two cases, one completely neglecting startup costs in the algorithm for cost-based technology assignment (STARTUP-FALSE), and one taking account of them, as set by default in the FederalPlan model (STARTUP-TRUE). The BAU2050 scenario is selected due to its greater significance of thermal power plants than in TARGET2050. Results are provided in FIGURE 32.



Indicator	Unit	STARTUP-FALSE	STARTUP-TRUE*
Total costs	bn. €/a	2.76	2.85
LCOE	€/MWh	76.26	77.38
Ann. CO_2	$MtCO_2/a$	4.63	4.66
Spec. CO_2	g/kWh	106.77	107.58
CO_2 reduction [rel. to 1990]	%	73.6%	73.4%

FIGURE 32. Sensitivity of selected FederalPlan outputs to startup costs in the BAU2050 scenario. Left: Technology shares in installed reserve capacity (i.e. excl. VRE). Right: Cost- and CO_2-related indicators, all excluding power imports. GT = open-cycle gas turbine; CCGT = combined-cycle gas turbine. (*) default parameter in scenario. Source: author's own.

It appears that differences between the two cases are only marginal. When taking account of startup costs (STARTUP-TRUE), some generation from inflexible natural gas-fired CCGTs is replaced by more flexible open-cycle gas turbines (OCGT). Due to the lower conversion efficiency of OCGTs compared to CCGTs (46% vs. 64%), both systems cost and CO_2 emissions are increasing in STARTUP-TRUE. System costs are about 3.3% higher due to greater total fuel costs, while CO_2 emissions are found to increase by 0.6%. Aside from the switch from CCGTs to OCGTs, no other significant changes are conceivable.

Concluding this section, the FederalPlan is found to be sensitive to changes in the CO_2 price, as well as the discount rate. These are essential parameters for every scenario analyses and thus be selected with caution. Furthermore, the shape of the load curve appears to have a small, yet important effect on system costs and CO_2 emissions. A more detailed evaluation of different load curve characteristics and their corresponding system impacts should thus be subject to further research. Finally, the consideration of startup costs in the investment planning and dispatch in the FederalPlan model only has marginal system effects. Yet, given the low computational complexity of its implementation and provision of realism in terms of variable costs, it should be maintained in the model. Based on this analysis, the following Chapter concludes on the overall robustness of outputs obtained from the FederalPlan model.

4.5. Conclusion: Robustness of the model outcomes

This chapter has elaborated on the ability of the FederalPlan modelling tool to deliver robust and plausible results in scenario analyses at federal state level with regard to the long-term dynamics of flexible power supply and structural changes in energy demand. For this purpose, a comparative assessment was set up for the case example of Baden-Württemberg, opposing essential outputs computed by FederalPlan with the ones obtained from the BW-POWER model. Three major conclusions can be drawn from this analysis.

First, FederalPlan shows a reasonable agreement with selected outputs from the BW-POWER model, including the deployment of power-to-heat electrode boilers and CHP plants. In turn, there are also various differences between the two models, which can be attributed to their contrasting modelling logic. FederalPlan only takes implicit account of long-lived capital stocks and the short-term adaptability of the energy system, possibly resulting in a possible underestimation of the assets still present in the system in 2050. In this regard, BW-POWER provides more detailed transition pathways. However, FederalPlan yields cost-effective system configurations, providing useful insights to decision makers with regard to the decisions needed today to reach long-term targets while avoiding stranded assets and capital lock-in effects. Overall, the comparative assessment performed here is not ideal. Instead of comparing FederalPlan to a model with an accounting logic (BW-POWER), a reference case should be found, similarly using a cost-based optimisation approach. This would allow for a more precise comparison of model outputs, focusing on distinct model uncertainties instead of on the overall modelling logic.

Second, the results from the FederalPlan model suggest that the trade-off between applying reduced levels of detail and obtaining highly robust model outputs cannot always be resolved. Particularly with regard to the operation and the economic implications of storage facilities and DSM interventions, the load band logic inherent to the algorithm for cost-based technology assignment appears to limit the endogenous deployment of these flexibility options. However, it needs to be emphasised that the BW-POWER provides no appropriate benchmark in this regard by only considering existing pumped hydro-electric as flexibility options in 2050. For this reason, as discussed previously in Chapter 3.5, the FederalPlan model should be coupled to a more detailed dispatch model, allowing for more scrutiny with regard to hourly storage and DSM operation, as well as operational constraints of thermal power plants.

Third, the degree of technological portfolio in the FederalPlan model was found to be too limited in some respects to provide plausible projections, especially when investigating scenarios with ambitious GHG emission reduction targets. In these cases, the model appears to overestimate power generation from fossil fuels and corresponding GHG emissions, while underestimating the contribution of technologies possibly being cost-effective in 2050, including geothermal energy, renewable waste and CHP-configurations for biomass and biomethane [46]. Overall, these additions can be easily implemented in the Excel-based framework of FederalPlan.

In addition to the comparative assessment, sensitivity analyses were carried out in order to evaluate the model's plausibility when altering certain input parameters. Results indicate reasonable changes in model outputs in response to CO_2 prices as well as the discount rate. Another interesting finding is the sensitivity of model outputs to the shape of the hourly load curve, giving rise to more elaborate research on this subject. In conclusion, the application example of the FederalPlan model performed in this chapter provides an elaborate overview of its capabilities for providing initial consultation, while highlighting its major difficulties in the practical implementation. Based on these insights, the following chapter refers back to the main research question.

5. Conclusion: Development of a modelling tool for providing initial consultation to federal state decision-makers

In the course of the increasing deployment of variable renewable energies, as well as ongoing structural changes in energy demand, decision-makers at a German federal state level must make difficult choices with regard to long-term investment planning and policy design. In this regard, model-based scenario analyses are a common means for substantiating decision making and providing policy-relevant insight. However, given their data needs and computational complexity, established modelling tools can be considered inappropriate for providing initial consultation. The present study is based on the assertion that the appropriateness of a modelling tool for providing initial consultation can be enhanced by making reasoned simplifications in terms of model detail, i.e. the multitude of real-world phenomena explicitly represented in the model. In this context, the study set out to investigate the following research question: *To what extent can a modelling tool with reduced levels of detail yield robust results in scenario analyses for investigating the* long-term dynamics between VRE supply an energy demand *at a German federal state level?*

In the following, an elaborate answer to this question is given (Section 5.1). Subsequently, a critical reflection on the applied methodology is provided (Section 5.2). Finally, the study finishes with a general outlook (Section 5.3).

5.1. Contributions to the scientific discussion

In order to answer the research question, the present study followed a three-step approach. First, it provided a comprehensive literature review of the unique properties of variable renewable energy generators, as well as the techno-economic integration challenges associated with their increasing deployment in power systems. The long-term challenges identified are flexibility, transmission capacity, voltage stability and frequency stability, with each of these being accompanied by long-term investment implications relevant for decision-makers and system planners. Based on research literature, it was found that the issue of flexibility has the most distinct investment implications, associated with the decreasing utilisation of baseload power plants and increasing costs for generator start-ups and ramping. Accordingly, future power supply configurations are likely to be characterised by a multitude of flexible power plants, storage facilities, power-to-heat and power-to-gas converters, as well as DSM measures. While the remaining integration challenges are likewise subject to long-term investment needs, they are neglected due to time constraints for carrying out the study. The interim conclusion being drawn is that a modelling tool, designed for providing initial consultation, should provide decision-makers with insights on the composition of flexible power supply in future, its cost-effectiveness and investment implications, as well as its interdependencies with structural changes in energy demand.

Subsequently, based on the theoretical considerations, the study introduced the novel modelling tool FederalPlan. Building upon established modelling techniques, the FederalPlan tool features two essential aspects. On the one hand, it projects future energy demand by means of a sectoral bottom-up accounting model, along with the alterations in hourly system load and the practical potentials for DSM that these developments incur. On the other hand, it projects cost-effective configurations for flexible power supply, covering a broad portfolio of power plants, storage and DSM facilities, as well as P2H and P2G converters. In the development of the model, emphasis was given to reducing data needs and computational complexity in order to make it useful for providing initial consultation. This is achieved by making reasoned simplifications with regard to temporal, technical and spatial model detail. A key element that should be highlighted in this regard is the algorithm for cost-based technology assignment, used to compute cost-optimal power supply configurations. In contrast to conventional linear- and mixed-integer programming approaches, this reduced-form optimisation is characterised by low computation times, providing nearly instantaneous results with regard to system configurations for conventional power plants, CHP plants, and P2X facilities. More elaborate model runs involving energy storage and DSM typically take 4 to 5 hours on a standard PC. Yet, in contrast to established long-term energy planning tools, this can still be considered as short. In addition to the relatively short computation time, the FederalPlan tool is characterised by limited data needs. While the supply side only requires a system load curve for the given region as well as the anticipated VRE capacities, the demand-side can be based on energy and end-use balances readily available for single federal states or for Germany. Overall, while the field of energy systems modelling clearly offers more sophisticated approaches, the FederalPlan tool allows for analysing a large set of parameters variations in a reasonable amount of time. This is a major asset for providing initial consultation, enabling decision makers to comprehend how changes in parameters and boundary conditions affect scenario outcomes.

Finally, the study evaluates the plausibility and robustness of the FederalPlan tool by comparing selected outputs to those from an established model-based scenario study for the federal state of Baden-Württemberg in 2050. For this purpose, a systematic comparative assessment is set up between FederalPlan and the reference model. The analyses reveals that, under equal boundary conditions, the outputs computed by the FederalPlan model show some similarities with the ones from the reference model. This includes the deployment of CHP, gas power plants, power-to-heat and storage facilities. In turn, there are differences with regard to the generation mix, as well as long-term CO_2 emissions from power supply. These differences can mostly be attributed to the different modelling logics applied in the two models, contrasting cost optimisation with a more narrative approach. As a result, the results obtained from the FederalPlan model can be generally considered plausible, while a more appropriate comparison with another cost-based optimisation (instead of accounting) model should be carried out to provide additional insights. In order to quantify the assertion of plausibility, sensitivity analysis are carried out for the model. According to the results, the model yields reasonable outputs in response to parameter changes in CO_2 prices, the discount rate, as well as the shape of the system load curve.

In conclusion, it is found that a modelling tool with reduced levels of detail can indeed provide robust results in scenario analyses for investigating the long-term dynamics between VRE supply and energy demand. In this regard, the present research makes important contributions to the research gaps identified in Chapter 1. First, it takes limited, yet explicit account of VRE-related integration challenges in scenario studies performed for German federal states. Second, it presents a modelling tool that is promising for providing initial consultation to federal state decision makers. Third, the methodical design of the model and its implementation is set out in a transparent and comprehensible manner. Nonetheless, the findings presented here certainly require critical reflection, as described in the following section.

5.2. Critical reflections

For the sake of providing a model suitable for initial consultation, the FederalPlan tool deliberately reduces detail with regard to the dynamics between variable renewable energy-based power supply and energy demand. Evidently, these simplifications need to be reflected upon, emphasizing their influence on model outputs and highlighting possible improvements for future versions of the modelling tool. In the following, the major critical issues are listed, following the previously used division into temporal, technical and spatial detail.

With regard to *temporal detail*, a major asset of the FederalPlan is its hourly resolution, providing non-aggregated time series of power supply and system load while retaining chronology and continuity between time steps. As the results have shown, this allows for detailed analyses of load shifting performed by storage and DSM facilities. However, with regard to the scenario time steps, the FederalPlan model reveals problematic issues. Using a greenfield approach, the model examines a single target year and does not explicitly model capital stock dynamics as well as existing and written-off assets in the power sector. As the results of the comparative assessment have shown, this approach may potentially underestimate the effect of incumbent fossil power generators on CO_2 emissions in the target year. Accordingly, one option for enhancing the model would be to adopt a capital stock approach for intermediate years. In this approach, existing power supply assets would be tracked regarding their technological lifetime. At the end of the lifetime, new technologies are deployed using the algorithm for cost-based technology assignment set out in this study. Here, it is important to ensure that the model does not become computationally unwieldy to keep it suitable for providing initial consultation. Overall, despite its greenfield approach, the FederalPlan tool still holds potential for providing useful insights on the future design of power systems. In order to reach long-term GHG reduction targets while preventing capital lock-in effects, policy makers today can utilise the model to identify technologies with high potential system relevance in future under given boundary conditions. Providing that these technologies only reach their projected long-term costs if they experience continuous deployment over the years and corresponding technology learning effects, policy makers are required to make decisions today for reaching future targets. This includes setting favourable legal frameworks (e.g. exploitation of underground caverns for storing renewable hydrogen and methane), initiating research and development (e.g. for geothermal energy), and implementing or extending support schemes (e.g. cogeneration from biomass).

Considering *technical detail*, the two major issues in the present version of the FederalPlan model include the *technological portfolio* and the consideration of *operational aspects* of power plants and flexibility options. With regard to the former, the FederalPlan features a wide range of conventional power plants, CHP plants and storage technologies, as well as the additional flexibility options DSM, P2H and P2G. Yet, as the comparative assessment in the results section has indicated, this portfolio should be subject to further extension. Particularly in scenarios with ambitious GHG reduction targets, additional renewable energy-based generators are necessary to represent the full range of possibly cost-effective technology options. This includes geothermal energy, renewable waste power plants, as well as biomass- and biomethane-based CHP. In addition to these power generators, the technological portfolio in the DSM potential assessment is limited, neglecting processes and appliances with distinct seasonal fluctuations, most notably heat pumps. Overall, the limited technological portfolio is likely to overestimate the contribution of conventional fossil-fuelled generators and corresponding CO_2 emissions in scenarios with high VRE-shares. However, its implementation in future versions of the model should represent no problem. With regard to operational aspects, the FederalPlan model features a cost parametrisation of operational constraints for power plants. As shown in the sensitivity analysis, the effect of this parametrisation on system costs and emissions is small, yet conceivable. However, it is important to stress that this parametrisation does not consider the actual technical feasibility of the dispatch projected by the model, with generator dispatch in reality being constrained by minimum load levels, partial load efficiencies and ramping capabilities. In accordance with established research, it is likely that the FederalPlan model underestimates operational costs of the generation mix and corresponding CO_2 emissions. Besides power plants, operational aspects require more precise modelling for storage and DSM facilities. Here, the load band logic inherent to model's supply system optimisation appears to lead to an underestimation of their load shifting potential in future. Overall, in order to scrutinise these operational aspects more comprehensively, a soft-coupling should be performed between the FederalPlan model and a more detailed production cost model. Based on the generation capacities determined by the FederalPlan model, the latter would recompute the operation of the power system under a greater level of technical detail, while considering the market- and price-based operation of single generation units at the power exchange. This approach would allow for adjusting operational parameters in the FederalPlan model, potentially enhancing the robustness of its outcomes.

Finally, regarding *spatial detail*, the FederalPlan model has issues in the definition of system boundaries. At present, the single federal state under consideration is set as the only internal region, requiring the balancing of power generation and system load within federal state boundaries. Representing other federal states, as well as neighbouring countries, a non-specified external region provides an exogenously amount of power imports to the federal state. This approach enables a low degree of computational complexity as well as a quick setup of scenarios for single federal states. Also it appeared sufficient with regard to the comparative assessment performed, given that the reference case did not use a more detailed approach either. However, it needs to be emphasised that the approach does not take account of the market-based power exchange that federal states are integrated into in reality. In a situation with low system load in a federal state and high load in surrounding regions, domestic power generators would ramp up in response to price signals. Considering that scenario studies for federal states frequently follow the source accounting principle, the FederalPlan is likely to underestimate CO_2 emissions from domestic power generation. Another issue arising from the narrow system boundaries is the negligence of spatial shifting as a flexibility option for VRE surpluses. As a consequence, the FederalPlan model might overstate the long-term investment needs for transforming the generation part of the power system.

In conclusion, applications of the FederalPlan model should take explicit account of these limitations in performing scenario analyses at a federal state level. Furthermore, in order to avoid misinterpretations on the side of contractors, modellers should ensure transparency and comprehensibility in the communication of model-based outcomes.

5.3. Outlook

As this research has illustrated, performing scenario analyses for decision-makers at a federal state level is embedded in a trade-off between reducing model complexity and retaining the model's explanatory power. From a scientific perspective, there is no optimality in this trade-off. Instead, scientific consultation must continue to provide flexible advisory concepts to its contractors, ranging from approaches for initial consultation to sophisticated modelling solutions. Against this backdrop, two general recommendations for future research can be derived – one referring to the FederalPlan model in particular, and one pointing towards general research concepts in the field of energy systems modelling.

The FederalPlan model should be extended to take more comprehensive account of the wide-ranging VRE-related integration challenges. While this study eventually focused on the issue of flexibility, the remaining integration challenges are not explicitly taken into account. In scenarios with high VRE shares, especially the issue of transmission capacity is relevant with regard to spatial pooling, i.e. mitigating the variability of VRE across large geographical areas. Furthermore, the requirements for voltage and frequency control should be considered along with their long-term investment implications, including reactive power compensation assets and additional active power reserves. Overall, as argued throughout this research, neglecting these challenges may result in misallocation of capital and a sub-optimal mix of power generation capacities. Another useful addition to the FederalPlan model would be an extension of its system focus. In its present setup, the model can be considered an energy system model, providing insights on both energy demand and energy supply. However, there is potential for improvement in two respects. On the one hand, accounting of CO_2 emissions and quantification of system costs in the model has so far only been performed with regard to power supply. This may lead to imbalanced conclusions being drawn from the modelling tool. For example, an increasing deployment of fuel-efficient CHP may result in emissions savings in the power sector, while increasing those of the district heating sector. Thus, the goal should be an integrated system perspective in the model, providing endogenously determined key outputs for every demand and supply sector, preferably including not only energy-related emissions, but also process-related emissions arising from the industry and agricultural sectors. On the other hand, the present implementation of sectoral energy demand in the FederalPlan model is based on an accounting framework. While this approach provides a reasonable level of detail with regard to sectoral end-uses and technologies, it does not consider the decision-making dynamics of firms, households and other actors in response to changes in fuel prices, technology costs, policies and other parameters. Accordingly, many input parameters for setting up scenarios are subject to estimates and assumptions on the part of the modeller, possibly leading to erroneous long-term projections. While this approach appears sufficient for providing a rough approximation of long-term developments as part of initial consultation, it would need to be complemented by more detailed simulation approaches in case a contractor asks for more elaborate demand-side projections.

With regard to general concepts, research in the field of energy systems modelling should increasingly systemise and scrutinise the complexity applied in the long-term planning tools applied. As described in the methodical discussion in Chapters 3.1 and 3.5, there have been recent attempts to quantify the effect of specific model components on model outcomes. For example, accounting for operational constraints of power plants is frequently found to result in higher greenhouse gas emissions in the model outputs. Likewise, the present study has investigated the effect of alterations in the shape of the system load curve on system costs and other outputs. However, what is lacking here is a systematic ranking of model components in order of their impact on model outputs. In other words, it is not clear what reduction in the degree of temporal, technical, and spatial detail is necessary to perturb model outputs. In this regard, also the perception on the part of contractors is important, i.e. the policy-makers, NGOs, utilities, and industry representatives commissioning scenario studies. Eventually, their specific requirements determine the credibility of modelling outcomes. Overall, in order to provide useful insights, modellers developers should ensure close collaboration with their target group.

6. References

[1] Hall Kirby G, Schleunes KA, Bayley C, Heather P, Hamerow T. Germany: Encyclopedia Britannica. [November 04, 2018]; Available from: https://www.britannica.com/place/Germany.

[2] IRENA. Planning for the Renewable Future: Long-term modelling and tools to expand variable renewable power in emerging economies. Abu Dhabi: International Renewable Energy Agency; 2017.

[3] Collins S, Deane JP, Poncelet K, Panos E, Pietzcker RC, Delarue E et al. Integrating short term variations of the power system into integrated energy system models: A methodological review. Renewable and Sustainable Energy Reviews 2017;76:839–56.

[4] Elsner P, Fischedick M, Sauer DU. Flexibilitätskonzepte für die Stromversorgung 2050: Technologien – Szenarien – Systemzusammenhänge. München: acatech – Deutsche Akademie der Technikwissenschaften; 2015.

[5] Johnson N, Strubegger M, McPherson M, Parkinson SC, Krey V, Sullivan P. A reduced-form approach for representing the impacts of wind and solar PV deployment on the structure and operation of the electricity system. Energy Economics 2017;64:651–64.

[6] Foley AM, Ó Gallachóir BP, Hur J, Baldick R, McKeogh EJ. A strategic review of electricity systems models. Energy 2010;35(12):4522–30.

[7] Pietzcker RC, Ueckerdt F, Carrara S, Boer HS de, Després J, Fujimori S et al. System integration of wind and solar power in integrated assessment models: A cross-model evaluation of new approaches. Energy Economics 2017;64:583–99.

[8] BMWi. Energiekonzept für eine umweltschonende, zuverlässige und bezahlbare Energieversorgung. Berlin: Bundesministerium für Wirtschaft und Technologie; 2010.

[9] Stephanos C, Höhne M-C (eds.). Coupling the different energy sectors: Options for the next phase of the energy transition. München: acatech – Deutsche Akademie der Technikwissenschaften e. V; 2018.

[10] Byfield S, Vetter D. Flexibility concepts for the German power supply in 2050: Ensuring stability in the age of renewable energies. München: acatech – Deutsche Akademie der Technikwissenschaften; 2016.

[11] Boßmann T. The contribution of electricity consumers to peak shaving and the integration of renewable energy sources by means of demand response: A model-based long-term scenario analysis in consideration of structural changes in electricity demand. Stuttgart: Fraunhofer Verlag; 2015.

[12] DeCarolis JF, Hunter K, Sreepathi S. The case for repeatable analysis with energy economy optimization models. Energy Economics 2012;34(6):1845–53.

[13] Mez L, Schneider S, Reiche D, Tempel S, Klinski S, Schmitz E. Zukünftiger Ausbau erneuerbarer Energieträger unter besonderer Berücksichtigung der Bundesländer: Endbericht für das Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit. Berlin: Forschungsstellefür Umweltpolitik (FFU); 2007.

[14] Münzner M. Energie und Klima Ländersache?: Landeskompetenzen zur Förderung von Energiewende und Klimaschutz. Rescriptum 2014(1).

[15] Diekmann J, Groba F. Erneuerbare Energien: Brandenburg und Bayern führen im Ländervergleich. DIW Wochenbericht 2012;79(50):3–11.

[16] Wurster S, Köhler C. Die Energiepolitik der Bundesländer: Scheitert die Energiewende am deutschen Föderalismus? In: Hildebrandt A, Wolf F, editors. Die Politik der Bundesländer. Wiesbaden: Springer; 2016, p. 283–314.

[17] Schlenzig C. PlaNet: Ein entscheidungsunterstützendes System für die Energie- und Umweltplanung. Stuttgart: Institut für Energiewirtschaft und Rationelle Energieanwendung; 1998.

[18] Behn R, Byfield S (eds.). Consulting with energy scenarios: Requirements for scientific policy advice. Munich: National Academy of Science and Engineering; 2016.

[19] Cao K-K, Cebulla F, Gómez Vilchez JJ, Mousavi B, Prehofer S. Raising awareness in model-based energy scenario studies—a transparency checklist. Energy, Sustainability and Society 2016;6(1):1–20.

[20] IRGC. Assessment of Future Energy Demand: A Methodological Review Providing Guidance to Developers and Users of Energy Models and Scenarios. Lausanne: International Risk Governance Council (IRGC); 2015.

[21] Mai T, Logan J, Blair N, Sullivan P, Bazilian M. RE-ASSUME: A Decision Maker's Guide to Evaluating Energy Scenarios, Modeling, and Assumptions. Paris: International Energy Agency; 2013.

[22] Blok K, Nieuwlaar E. Introduction to Energy Analysis. London: Routledge; 2016.

[23] van Beeck NMJP. Classification of Energy Models. Tilburg: Tilburg University; 1999.

[24] Connolly D, Lund H, Mathiesen BV, Leahy M. A review of computer tools for analysing the integration of renewable energy into various energy systems. Applied Energy 2010;87(4):1059–82.

[25] Després J, Hadjsaid N, Criqui P, Noirot I. Modelling the impacts of variable renewable sources on the power sector: Reconsidering the typology of energy modelling tools. Energy 2015;80:486–95.

[26] Hourcade J-C, Jaccard M, Bataille C, Ghersi F. Hybrid Modeling: New Answers to Old Challenges Introduction to the Special Issue of "The Energy Journal". The Energy Journal 2006;27:1–11.

[27] van Vuuren DP, Hoogwijk M, Barker T, Riahi K, Boeters S, Chateau J et al. Comparison of top-down and bottom-up estimates of sectoral and regional greenhouse gas emission reduction potentials. Energy Policy 2009;37(12):5125–39.

[28] Stockholm Environment Institute. LEAP: Long-range Energy Alternatives Planning. [November 05, 2018]; Available from: www.energycommunity.org/Default.asp.

[29] International Energy Agency (IEA). MARKAL: MARKet ALlocation. [November 05, 2018]; Available from: http://iea-etsap.org/index.php/etsap-tools/modelgenerators/.

[30] KTH Royal Institute of Technology. OSeMOSYS: Open Source Energy Modelling System. [November 05, 2018]; Available from: www.osemosys.org/.

[31] Haydt G, Leal V, Pina A, Silva CA. The relevance of the energy resource dynamics in the mid/long-term energy planning models. Renewable Energy 2011;36(11):3068–74.

[32] Welsch M, Deane P, Howells M, Ó Gallachóir B, Rogan F, Bazilian M et al. Incorporating flexibility requirements into long-term energy system models – A case study on high levels of renewable electricity penetration in Ireland. Applied Energy 2014;135:600–15.

[33] Lund HH. Renewable energy systems: A smart energy systems approach to the choice and modeling of 100% renewable solutions. Boston: Academic Press; 2014.

[34] Weber A, Buttermann HG, Baten T, Bohnenschäfer W. Bayerische Energieszenarien 2050: Endbericht. München: Bayerisches Staatsministerium für Wirtschaft, Infrastruktur, Verkehr und Technologie; 2012.

[35] Kralemann M, Schröder S, Mannstedt T. BUND-Szenario: Energieversorgung in Niedersachsen im Jahr 2050. Hannover: Bund für Umwelt und Naturschutz Deutschland; 2018.

[36] Schindler H, Carl M, Paulus J, Yacoub S, Ullrich M. Energiewende Rheinland-Pfalz: Neuer Fahrplan. Mainz: Bund für Umwelt und Naturschutz Deutschland (BUND); 2018.

[37] Ebert M, Erfurt I, Gansler J, Lorenz C, Reichmuth M, Scheuermann A. Gutachten zur Vorbereitung einer Energie- und Klimaschutzstrategie für Thüringen. Leipzig: Leipziger Institut für Energie GmbH; 2016.

[38] Faulstich M, Beck H-P, Haaren C von, Kuck J, Rode M, Ahmels J et al. Szenarien zur Energieversorgung in Niedersachsen im Jahr 2050: Gutachten. Hannover: Niedersächsisches Ministerium für Umwelt, Energie und Klimaschutz; 2016.

[39] Frederking D, Schmidt-Kanefendt H-H, Schneider A. Konzept einer zukunftsfähigen Energieversorgung: Eine Zukunft mit 100 % Erneuerbaren Energien Sachsen-Anhalt als Energieexportland. Magdeburg: Fraktion BÜNDNIS 90/DIE GRÜNEN im Landtag von Sachsen-Anhalt; 2015.

[40] Reusswig F, Hirschl B, Lass W, Becker C, Bölling L, Clausen W et al. Klimaneutrales Berlin 2050: Machbarkeitsstudie: Hauptbericht. Berlin: Senatsverwaltung für Stadtentwicklung und Umwelt; 2014.

[41] Spataru C. Whole Energy System Dynamics: Theory, Modelling, and Policy. London: Routledge; 2017.

[42] Crespo del Granado P, van Nieuwkoop RH, Kardakos EG, Schaffner C. Modelling the energy transition: A nexus of energy system and economic models. Energy Strategy Reviews 2018;20:229–35.

[43] Fawcett AA, Calvin KV, La Chesnaye FC de, Reilly JM, Weyant JP. Overview of EMF 22 U.S. transition scenarios. Energy Economics 2009;31:S198-S211.

[44] FEES (ed.). Energiemodelle zum Klimaschutz in Deutschland. Heidelberg: Physica Verlag; 1999.

[45] Strachan N, Fais B, Daly H. Reinventing the energy modelling–policy interface. Nature Energy 2016;1(3):16012.

[46] Lunz B, Stöcker P, Eckstein S, Nebel A, Samadi S, Erlach B et al. Scenario-based comparative assessment of potential future electricity systems – A new methodological approach using Germany in 2050 as an example. Applied Energy 2016;171:555–80.

[47] Després J, Hadjsaid N, Criqui P, Noirot I. Modelling the impacts of variable renewable sources on the power sector: Reconsidering the typology of energy modelling tools. Energy 2015;80:486–95.

[48] Pfenninger S, Hawkes A, Keirstead J. Energy systems modeling for twenty-first century energy challenges. Renewable and Sustainable Energy Reviews 2014;33:74–86.

[49] Greening LA, Bataille C. Bottom-up models of energy: across the spectrum. In: Evans J, Hunt LC, editors. International Handbook on the Economics of Energy. Cheltenham: Edward Elgar; 2009, p. 257–284.

[50] Schmidt M, Fuchs A-L, Kelm T, Abdalla N, Bergk F, Fehrenbach H et al. Energie- und Klimaschutzziele 2030. Stuttgart (i.a.): ZSW/ifeu/Öko-Institut/Fraunhofer ISI/Hamburg Institut; 2017.

[51] Gómez-Schiavon M, El-Samad H. Complexity-aware simple modeling. Current opinion in microbiology 2018;45:47–52.

[52] Statistisches Landesamt Baden-Württemberg. Statistik-Portal. [April 25, 2018]; Available from: https://www.statistik-bw.de/.

[53] Statistisches Landesamt Sachsen-Anhalt. Interaktive Datenbank. [July 27, 2018]; Available from: https://www.statistik.sachsen-anhalt.de/index.html.

[54] Wainwright J, Mulligan M. Introduction: Why model the environment? In: Wainwright J, Mulligan M, editors. Environmental Modelling: Finding Simplicity in Complexity. Chichester: Wiley; 2013, p. 3–6.

[55] Pfenninger S. Dealing with multiple decades of hourly wind and PV time series in energy models: A comparison of methods to reduce time resolution and the planning implications of inter-annual variability. Applied Energy 2017;197:1–13.

[56] Hoffman KC, Wood DO. Energy System Modeling and Forecasting. Annual Review of Energy 1976;1(1):423–53.

[57] Salimi F, Salimi F. Systems Approach to Managing the Complexities of Process Industries. Amsterdam: Elsevier; 2018.

[58] Pfenninger S. Energy scientists must show their workings. Nature 2017;542(7642):393.

[59] European Commission. Energy Roadmap 2050. Brussels: European Union; 2012.
[60] Pfenninger S, DeCarolis J, Hirth L, Quoilin S, Staffell I. The importance of open data and software: Is energy research lagging behind? Energy Policy 2017;101:211–5.
[61] Gass SI, Hoffman KL, Jackson RHF, Joel LS, Saunders PB. Documentation for a Model: A Hierarchical Approach. Communications of the ACM 1981;24(11):728–33.
[62] Risbey J, van der Sluijs J, Kloprogge P, Ravetz J, Funtowicz S, Corral Quintana S. Application of a checklist for quality assistance in environmental modelling to an energy model. Environmental Modeling & Assessment 2005;10(1):63–79.
[63] Bazilian M, Rice A, Rotich J, Howells M, DeCarolis J, Macmillan S et al. Open source software and crowdsourcing for energy analysis. Energy Policy 2012;49:149–53.
[64] Pfenninger S, Hirth L, Schlecht I, Schmid E, Wiese F, Brown T et al. Opening the black box of energy modelling: Strategies and lessons learned. Energy Strategy Reviews 2018;19:63–71.
[65] Vries Bd. Sustainability Science. Cambridge: University Press; 2017.
[66] Droste-Franke B, Carrier M, Kaiser M, Schreurs M, Weber C, Ziesemer T. Improving Energy Decisions: Towards Better Scientific Policy Advice for a Safe and Secure Future Energy System. Cham: Springer; 2015.
[67] Bhattacharyya SC. Energy Economics: Concepts, Issues, Markets and Governance. London: Springer; 2011.
[68] Zweifel P, Praktiknjo A, Erdmann G. Energy Economics: Theory and Applications. Heidelberg: Springer; 2017.
[69] Neresian RL. Energy Economics: Markets, History and Policy. London: Routledge; 2016.
[70] Kästner T, Kießling A. Energiewende in 60 Minuten: Ein Reiseführer durch die Stromwirtschaft. Wiesbaden: Springer VS; 2015.
[71] EPIA. Connecting the Sun: Solar Photovoltaics on the Road to Large-Scale Grid Integration. Brussels: European Photovoltaic Industry Association; 2012.
[72] Pöller M. Power System Security in Developing and Emerging Countries. Bonn: Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ); 2015.
[73] Dreidy M, Mokhlis H, Mekhilef S. Inertia response and frequency control techniques for renewable energy sources: A review. Renewable and Sustainable Energy Reviews 2017;69:144–55.
[74] ENTSO-E. ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators. Brussels: European Network of Transmission System Operators for Electricity; 2012.
[75] Michaelis J, Muller T, Reiter U, Fermi F, Wyrwa A, Chen Y-k et al. Comparison of the techno-economic characteristics of different flexibility options in the European energy system. In: IEEE, editor. 14th International Conference on the European Energy Market (EEM): IEEE; 2017, p. 1–5.

[76] Ludig S, Haller M, Schmid E, Bauer N. Fluctuating renewables in a long-term climate change mitigation strategy. Energy 2011;36(11):6674–85.

[77] Papaefthymiou G, Grave K, Dragoon K. Flexibility options in electricity systems. Berlin: Ecofys; 2014.

[78] International Energy Agency (IEA). The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems. Paris: International Energy Agency; 2014.

[79] Görner K, Sauer DU (eds.). Konventionelle Kraftwerke: Technologiesteckbrief zur Analyse „Flexibilitätskonzepte für die Stromversorgung 2050“. München: acatech – Deutsche Akademie der Technikwissenschaften e. V; 2016.

[80] Klinge Jacobsen H, Schröder ST. Curtailment of renewable generation: Economic optimality and incentives. Energy Policy 2012;49:663–75.

[81] Narbel PA, Hansen JP, Lien JR. Energy Technologies and Economics. Cham: Springer International Publishing; 2014.

[82] Buber T, Gruber A, Klobasa M, Roon S von. Lastmanagement für Systemdienstleistungen und zur Reduktion der Spitzenlast. Vierteiljahreshefte zur Wirtschaftsforschung 2013;82(3):89–106.

[83] Sauer DU (ed.). Stromnetze: Technologiesteckbrief zur Analyse „Flexibilitätskonzepte für die Stromversorgung 2050“. München: acatech – Deutsche Akademie der Technikwissenschaften; 2016.

[84] Tielens P, van Hertem D. The relevance of inertia in power systems. Renewable and Sustainable Energy Reviews 2016;55:999–1009.

[85] Poncelet K, Delarue E, Six D, Duerinck J, D'haeseleer W. Impact of the level of temporal and operational detail in energy-system planning models. Applied Energy 2016;162:631–43.

[86] Kotzur L, Markewitz P, Robinius M, Stolten D. Impact of different time series aggregation methods on optimal energy system design. Renewable Energy 2018;117:474–87.

[87] Ueckerdt F, Brecha R, Luderer G, Sullivan P, Schmid E, Bauer N et al. Representing power sector variability and the integration of variable renewables in long-term energy-economy models using residual load duration curves. Energy 2015;90:1799–814.

[88] {Holttinen 2011 #460}.

[89] Dodds PE, Keppo I, Strachan N. Characterising the Evolution of Energy System Models Using Model Archaeology. Environmental Modeling & Assessment 2015;20(2):83–102.

[90] Borggrefe F, Pregger T, Gils HC, Cao K-K, Deissenroth M, Bothor S et al. Kurzstudie zur Kapazitätsentwicklung in Süddeutschland bis 2025 - unter Berücksichtigung der Situation in Deutschland und den europäischen Nachbarstaaten: Im Auftrag des Ministeriums für Umwelt, Klima und Energiewirtschaft Baden-Württemberg. Stuttgart: Deutsches Zentrum für Luft- und Raumfahrt (DLR)/Institut für Energiewirtschaft und Rationelle Energieanwendung (IER); 2015.

[91] Twele J, Müller B, Möller C. Szenarioberechnung einer Strom- und Wärmeversorgung der Region Brandenburg-Berlin auf Basis Erneuerbarer Energien. Berlin: Reiner Lemoine Institut; 2012.

[92] Hamacher T, Ahlhaus P, Kandler C. Bayerische Stromversorgung im Jahr 2022: Kurzstudie im Auftrag der SPD Bayern. München: Technische Universität München; 2012.

[93] Ministerium für Umwelt, Klima und Energiewirtschaft. Integriertes Energie- und Klimaschutzkonzept Baden-Württemberg (IEKK). Stuttgart: Ministerium für Umwelt, Klima und Energiewirtschaft Baden-Württemberg; 2015.

[94] Pfenninger S, Staffell I. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 2016;114:1251–65.

[95] Boßmann T, Staffell I. The shape of future electricity demand: Exploring load curves in 2050s Germany and Britain. Energy 2015;90:1317–33.

[96] Scholz Y. Renewable energy based electricity supply at low costs: Development of the REMix model and application for Europe. Stuttgart: Universität Stuttgart, Institut für Thermodynamik und Wärmetechnik; 2012.

[97] Staffell I. DESTinEE / ETRC: Energy Transfer Reference Case. [November 05, 2018]; Available from: https://sites.google.com/site/2050destinee/.

[98] DTU Management Engineering. STREAM: Energy system model. [November 05, 2018]; Available from: http://streammodel.org/contact.html.

[99] International Atomic Energy Agency (IAEA). MAED: Model for Analysis of Energy Demand. [November 05, 2018]; Available from: https://www-pub.iaea.org/books/iaeabooks/7430/Model-for-Analysis-of-Energy-Demand-MAED-2.

[100] Munasinghe M, Meier P. Energy Policy Analysis and Modeling. Cambridge: University Press; 1993.

[101] Hall LMH, Buckley AR. A review of energy systems models in the UK: Prevalent usage and categorisation. Applied Energy 2016;169:607–28.

[102] Bhattacharyya SC, Timilsina GR. Energy Demand Models for Policy Formulation: A Comparative Study of Energy Demand Models. Washington: World Bank; 2009.

[103] Herbst A, Toro F, Reitze F, Jochem E. Introduction to Energy Systems Modelling. Swiss Journal of Economics and Statistics 2012;148(2):111–35.

[104] Medlock KB. Energy demand theory. In: Evans J, Hunt LC, editors. International Handbook on the Economics of Energy. Cheltenham: Edward Elgar; 2009, p. 89–111.

[105] Klinge Jacobsen H. Integrating the bottom-up and top-down approach to energy–economy modelling: The case of Denmark. Energy Economics 1998;20(4):443–61.

[106] Pfluger B. Assessment of least-cost pathways for decarbonising Europe's power supply: A model-based long-term scenario analysis accounting for the characteristics of renewable energies. Karlsruhe: KIT Scientific Publishing; 2014.

[107] Pye S, Bataille C. Improving deep decarbonization modelling capacity for developed and developing country contexts. Climate Policy 2016;16:S27-S46.

[108] Länderarbeitskreis Energiebilanzen. Energie- und CO2-Bilanzen. [June 18, 2018]; Available from: http://www.lak-energiebilanzen.de/.

[109] Frondel M, Janßen-Timmen R, Sommer S. Erstellung der Anwendungsbilanzen 2014 bis 2015 für den Sektor der Privaten Haushalte und den Verkehrssektor in Deutschland: Endbericht - Oktober 2016. Forschungsprojekt im Auftrag des Bundesministeriums für. Essen: Leibniz-Institut für Wirtschaftsforschung; 2016.

[110] Quintel Intelligence. Energy Transition Model: Create your own Energy Future. [September 05, 2018]; Available from: https://energytransitionmodel.com/.

[111] Umweltbundesamt. Konsum und Produkte. [September 06, 2018]; Available from: https://www.umweltbundesamt.de/daten/private-haushalte-konsum/konsum-produkte/ausstattung-privater-haushalte-gebrauchsguetern%20-%20textpart-2.

[112] Styczynski Z, Sauer DU (eds.). Demand-Side-Management im Strommarkt: Technologiesteckbrief zur Analyse „Flexibilitätskonzepte für die Stromversorgung 2050“. München: acatech (Deutsche Akademie der Technikwissenschaften); 2015.

[113] Statistisches Landesamt Baden-Württemberg. Verkehr in Baden-Württemberg. Stuttgart: Statistisches Landesamt Baden-Württemberg; 2012.

[114] Knörr W, Heidt C, Gores S, Bergk F. Aktualisierung „Daten- und Rechenmodell: Energieverbrauch und Schadstoffemissionen des motorisierten Verkehrs in Deutschland 1960-2035“ (TREMOD) für die Emissionsberichterstattung 2016 (Berichtsperiode 1990-2014): Projektnummer 54329. Heidelberg: Ifeu-Institut für Energie- und Umweltforschung Heidelberg GmbH; 2016.

[115] Rohde C. Erstellung von Anwendungsbilanzen für die Jahre 2013 bis 2016: Studie für die Arbeitsgemeinschaft Energiebilanzen e.V. (AGEB) - Entwurf. Karlsruhe: Fraunhofer-Institut für System- und Innovationsforschung; 2017.

[116] Statistisches Bundesamt. Klassifikation der Wirtschaftszweige: Mit Erläuterungen. Wiesbaden: Statistisches Bundesamt; 2008.

[117] Kleeberger H, Hardi L, Geiger B. Erstellen der Anwendungsbilanzen 2013 bis 2016 für den Sektor Gewerbe, Handel, Dienstleistungen (GHD): Im Auftrag der Arbeitsgemeinschaft Energiebilanzen e.V., Berlin. München: Technische Universität München; 2017.

[118] Boßmann T, Elsland, Lickert, Fridolin, Wietschel M. The German load curve in 2050: structural changes through energy efficiency measures and their impacts on the electricity supply side. In: ECEEE, editor. ECEEE 2013 Summer Study; 2013, p. 1199–1211.

[119] Hainoun A. Construction of the hourly load curves and detecting the annual peak load of future Syrian electric power demand using bottom-up approach. International Journal of Electrical Power & Energy Systems 2009;31(1):1–12.

[120] ENTSO-E. Power statistics: Monthly hourly load values. [October 01, 2018]; Available from: https://www.entsoe.eu/data/power-stats/.

[121] Transnet BW. Kennzahlen: Lastverlauf (Netzeinspeisung). [October 01, 2018]; Available from: https://www.transnetbw.de/de/transparenz/marktdaten/kennzahlen.

[122] Gils HC. Assessment of the theoretical demand response potential in Europe. Energy 2014;67:1–18.

[123] Gils HC. Economic potential for future demand response in Germany – Modeling approach and case study. Applied Energy 2016;162:401–15.

[124] Steurer M. Analyse von Demand Side Integration im Hinblick auf eine effiziente und umweltfreundliche Energieversorgung: Dissertation. Stuttgart: Institut für Energiewirtschaft und Rationelle Energieanwendung; 2017.

[125] Fleiter T, Schlomann B, Eichhammer W. Energieverbrauch und CO2-Emissionen industrieller Prozesstechnologien – Einsparpotenziale, Hemmnisse und Instrumente. Karlsruhe: Fraunhofer-Institut für System- und Innovationsforschung; 2013.

[126] Pfenninger S, Staffell I. Renewables.ninja: Hourly simulations of wind and solar output. [September 23, 2018]; Available from: https://www.renewables.ninja/.

[127] Staffell I, Pfenninger S. Using bias-corrected reanalysis to simulate current and future wind power output. Energy 2016;114:1224–39.

[128] Quentin J, Sondershaus F. Ausbausituation der Windenergie an Land im Jahr 2017: Auswertung windenergiespezifischer Daten im Marktstammdatenregister für den Zeitraum Januar bis Dezember 2017. Berlin: Fachagentur Windenergie an Land; 2018.

[129] Quaschning V. System-technik einer klima-verträg-lichen Elektri-zitäts-versorgung in Deutschland für das 21. Jahrhundert; 2000.

[130] Rech B, Elsner P (eds.). Photovoltaik: Technologiesteckbrief zur Analyse „Flexibilitätskonzepte für die Stromversorgung 2050“. München: acatech – Deutsche Akademie der Technikwissenschaften; 2016.

[131] Kost C, Shammugam S, Jülch V, Nguyen H-T, Schlegl T. Levelized Cost of Electricity: Renewable Energy Technologies. Freiburg: Fraunhofer-Institut für Solare Energiesysteme (ISE); 2018.

[132] Blesl M, Kessler A. Energieeffizienz in der Industrie. Berlin, Heidelberg: Springer Berlin Heidelberg; 2013.

[133] Deac G. Stündliche Heizlastkurve für Verbraucher in Haushalten und Gewerbe. Karlsruhe: Fraunhofer-Institut für System- und Innovationsforschung (ISI); 2018.

[134] Pehnt M (ed.). Energieeffizienz: Ein Lehr- und Handbuch. Berlin: Springer Berlin Heidelberg; 2010.

[135] Konstantin P, Konstantin M. Power and Energy Systems Engineering Economics. Cham: Springer International Publishing; 2018.

[136] Schubert G, Sensfuß F, Nast, Michasel, Fette, Max, Eikmeier B. Kopplung von Strom- und Wärmemarkt vor dem Hintergrund eines steigenden Anteils erneuerbarer Energien. Karlsruhe: Fraunhofer-Institut für System- und Innovationsforschung (ISI); 2014.

[137] Choi J, Park W-K, Lee I-W. Economic Dispatch of Multiple Energy Storage Systems Under Different Characteristics. Energy Procedia 2017;141:216–21.

[138] Nweke CI, Leanez F, Drayton GR, Kolhe M. Benefits of chronological optimization in capacity planning for electricity markets. In: IEEE International Conference on Power System Technology (POWERCON), 2012: Auckland, New Zealand, Oct. 30, 2012 - Nov. 2, 2012. Piscataway, NJ: IEEE; 2012, p. 1–6.

[139] Welsch M, Howells M, Hesamzadeh MR, Ó Gallachóir B, Deane P, Strachan N et al. Supporting security and adequacy in future energy systems: The need to enhance long-term energy system models to better treat issues related to variability. International Journal of Energy Research 2015;39(3):377–96.

[140] Reddy TA. Applied Data Analysis and Modeling for Energy Engineers and Scientists. Boston: Springer US; 2011.

[141] Nakata T. Energy-economic models and the environment. Progress in Energy and Combustion Science 2004;30(4):417–75.

[142] Sensfuß F. Assessment of the impact of renewable electricity generation on the German electricity sector: An agent-based simulation approach. Karlsruhe: Universität Karlsruhe; 2007.

[143] Debnath KB, Mourshed M. Forecasting methods in energy planning models. Renewable and Sustainable Energy Reviews 2018;88:297–325.

[144] Encyclopaedia Britannica. Baden-Württemberg: State, Germany. [October 25, 2018]; Available from: https://www.britannica.com/place/Baden-Wurttemberg.

[145] Landtag von Baden-Württemberg. Gesetz zur Förderung des Klimaschutzes in Baden-Württemberg: Drucksache 15 / 3842. Stuttgart: Landtag von Baden-Württemberg; 2013.

[146] Schmidt M, Staiß F, Salzer J, Nitsch J. Gutachten zur Vorbereitung eines Klimaschutzgesetzes für Baden-Württemberg: Im Auftrag des des Ministeriums für Umwelt, Klimaschutz und Energiewirtschaft Baden-Württemberg. Aktualisiert Fassung. Stuttgart: Zentrum für Sonnenenergie- und Wasserstoff-Forschung Baden-Württemberg (ZSW); 2012.

[147] BMWi. Die Energie der Zukunft: Erster Fortschrittsbericht zur Energiewende. Berlin: Bundesministerium für Wirtschaft und Energie; 2014.

[148] Schlesinger M, Lindenberger D, Lutz C (eds.). Entwicklung der Energiemärkte: Energiereferenzprognose. Projekt Nr. 57/12. Basel/Köln/Osnabrück: Prognos AG; 2014.

[149] Umweltbundesamt (ed.). CO2-Emissionsfaktoren für fossile Brennstoffe. Dessau-Roßlau: Umweltbundesamt; 2016.

[150] Ministerium für Umwelt, Klima und Energiewirtschaft. Erneuerbare Energien in Baden-Württemberg 2015. Stuttgart: Ministerium für Umwelt, Klima und Energiewirtschaft; 2015.

[151] Elsner P, Sauer DU (eds.). Energiespeicher: Technologiesteckbrief zur Analyse „Flexibilitätskonzepte für die Stromversorgung 2050" Peter Elsner | Dirk Uwe Sauer (Hrsg.) „Energiesysteme. München: acatech – Deutsche Akademie der Technikwissenschaften; 2015.

[152] Cebulla F, Naegler T, Pohl M. Electrical energy storage in highly renewable European energy systems: Capacity requirements, spatial distribution, and storage dispatch. Journal of Energy Storage 2017;14:211–23.

[153] Staffell I, Rustomji M. Maximising the value of electricity storage. Journal of Energy Storage 2016;8:212–25.

[154] Mulligan M, Wainwright J. Modelling and Model Building. In: Wainwright J, Mulligan M, editors. Environmental Modelling: Finding Simplicity in Complexity. Chichester: Wiley; 2013, p. 7–26.

[155] Hübler M, Löschel A. The EU Decarbonisation Roadmap 2050—What way to walk? Energy Policy 2013;55:190–207.

[156] Steinbach J. Discount rates in energy system analysis: Discussion Paper. Karlsruhe: Fraunhofer-Institut für System- und Innovationsforschung (ISI); 2015.

[157] Reuter A, Elsner P (eds.). Windkraftanlagen: Technologiesteckbrief zur Analyse „Flexibilitätskonzepte für die Stromversorgung 2050". München: acatech – Deutsche Akademie der Technikwissenschaften; 2016.

[158] Ministerium für Verkehr Baden-Württemberg (ed.). Klimaschutz-Szenario Baden-Württemberg 2030. München/Aachen/Freiburg/Essen: ITP/IVV/TRIMODE; 2017.

[159] Schlomann B, Wohlfahrt K, Kleeberger H, Hardi L, Geiger B, Pich A et al. Energieverbrauch des Sektors Gewerbe, Handel, Dienstleistungen (GHD) in Deutschland für die Jahre 2011 bis 2013: Schlussbericht an das Bundesministerium für Wirtschaft und Energie (BMWi). Karlsruhe/München/Nürnberg/Freiburg: Fraunhofer-Institut für System- und Innovationsforschung (ISI)/Lehrstuhl für Energiewirtschaft und Anwendungstechnik (IfE)/GfK Retail and Technology GmbH; 2015.

7. Appendix

7.1. Overview of energy and climate policy targets in German federal states

TABLE 23. Overview of existing energy and climate policy targets in German federal states. Status as of 2016. Source: [16].

Target category																
State code	BW	BY	B	BB	HB	HH	HE	MV	NI	NRW	RLP	SL	SN	ST	SH	TH
Electricity	✓	✓	-	✓	✓	-	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Hydropower	✓	✓	-	-	✓	-	-	-	-	-	✓	-	-	-	-	-
Biomass	✓	✓	-	-	-	-	-	✓	-	-	-	✓	-	-	-	-
Photovoltaics	✓	✓	-	-	✓	-	-	✓	-	-	✓	✓	-	-	-	-
Wind power	✓	✓	-	-	✓	✓	-	✓	✓	✓	✓	✓	-	-	-	-
Geothermal	-	✓	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Heat	✓	-	-	-	✓	-	✓	✓	-	-	-	-	-	-	✓	-
Biomass	✓	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar thermal	✓	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	✓	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy eff.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHP	✓	✓	-	-	-	-	-	-	-	✓	✓	-	✓	-	✓	-
Electricity consumption	✓	✓	-	-	-	-	-	-	-	-	-	-	-	-	✓	✓
Primary energy	-	-	-	✓	-	-	-	-	-	-	-	-	-	-	✓	-
Final energy	✓	-	-	✓	-	-	✓	-	✓	-	-	-	-	-	✓	-
GHG reduction	✓	✓	✓	✓	✓	✓	-	✓	✓	✓	✓	✓	✓	✓	✓	-

7.2. Default technology parameters

TABLE 24. Default parameters for technologies in the household sector in 2050. Source: [110].

Technology	Efficiency	Unit
Space heating		
Coal-fired heater	80.0%	%
Condensing gas boiler	106.7%	%
District heating	100.0%	%
Electric heater	100.0%	%
Heat pump	350.0%	%
Oil-fired heater	85.0%	%
Solar thermal collector	100.0%	%
Wood pellet stove	82.0%	%
Hot water		
Coal-fired boiler	80.0%	%
Condensing gas boiler	90.0%	%
District heating	100.0%	%
Electric boiler	100.0%	%
Heat pump	300.0%	%
Oil-fired boiler	85.0%	%
Solar thermal collector	100.0%	%
Wood pellet boiler	82.0%	%
Cooking		
Electric stove	55.0%	%
Gas stove	40.0%	%
Induction stove	85.0%	%
White appliances		
Dish washer	0.37	kW/unit
Freezer	0.15	kW/unit
Refrigerator	0.15	kW/unit
Tumble dryer	1.25	kW/unit
Washing machine	0.18	kW/unit
Air conditioning		
Air conditioner	1.70	kW/unit

TABLE 25. Default parameters for technologies in the transport sector in 2050. Source: [110,114].

Category	Modal split	Technology	Efficiency	Unit
Passenger transport	Cars	CNG	0.63	pkm/MJ
		Diesel oil	0.70	pkm/MJ
		Plug-in EV	2.04	pkm/MJ
		Hydrogen	1.35	pkm/MJ
		LPG	0.66	pkm/MJ
		Gasoline	0.63	pkm/MJ
	Trains	Diesel	1.50	pkm/MJ
		Electricity	3.70	pkm/MJ
		Hard coal	0.50	pkm/MJ
	Trams/metros	Tram/metro	1.63	pkm/MJ
	Busses	CNG	1.38	pkm/MJ
		Diesel	1.24	pkm/MJ
		Electricity	2.84	pkm/MJ
		Hydrogen	1.89	pkm/MJ
		LNG	1.38	pkm/MJ
		Gasoline	1.13	pkm/MJ
	Motorcycles	Electricity	9.10	pkm/MJ
		Gasoline	0.89	pkm/MJ
	Bicycles	(no fuel)	-	pkm/MJ
		Electricity	28.57	pkm/MJ
	Domestic planes	Bioethanol	0.18	pkm/MJ
		Kerosene	0.29	pkm/MJ
		Gasoline	0.31	pkm/MJ
Freight transport	Truck	CNG	0.63	tkm/MJ
		Diesel	0.66	tkm/MJ
		Electricity (overhead line)	1.11	tkm/MJ
		Hydrogen	0.93	tkm/MJ
		LNG	0.69	tkm/MJ
		Gasoline	0.60	tkm/MJ
				tkm/MJ
	Train	Diesel	2.70	tkm/MJ
		Electricity	7.14	tkm/MJ
	Domestic navigation	Diesel	1.01	tkm/MJ
		LNG	0.98	tkm/MJ

TABLE 26. Default parameters for technologies in the tertiary sector in 2050. Source: [110].

Technology	Efficiency	Unit
Space heating		
Coal-fired heater	80.0%	%
District heating	100.0%	%
Electric heater	100.0%	%
Gas-fired heater	90.0%	%
Heat pump	200.0%	%
Oil-fired heater	85.0%	%
Solar thermal panels	95.0%	%
Biomass-fired heater	82.0%	%

TABLE 27. Default cost parameters for PV, wind and hydro power in 2050. Source: [46,130,157].

Photovoltaics (PV)			
Parameter	Unit	Rooftop	Field
Module costs	€/kWp	300	250
Inverter costs	€/kWp	65	50
Balance of system costs	€/kWp	225	165
O&M costs	€/kWp/a	10	10
Lifetime modules	years	37.5	37.5
Lifetime inverter	years	25	25
Wind			
Parameter	Unit	Onshore	Offshore
Installation cost	€/kW	950	2,750
Grid access	€/kW	75	485
Rent for land use	€/MWh	7.5	0
O&M costs	€/MWh	12.5	15.0
Lifetime	years	22.5	22.5
Hydro			
Parameter	Unit	Value	
LCOE	€/MWh	62.60	

TABLE 28. Default cost and technology parameters for thermal power plants in 2050. Source: [46,79].

Technology	Fuel	η_{el}	u	c_I	$c_{O\&M}$	$c_{start,cold}$	$c_{start,warm}$
		$[\%]$	$[years]$	$[€/GW_{el}]$	$[\%/a]$	$[€/(GW_{el} * no.)]$	$[€/(GW_{el} * no.)]$
Steam turbine	Hard coal	50%	40	1,400 m	2.6%	60,000	40,000
Steam turbine	Lignite	50%	40	1,800 m	3.3%	30,000	20,000
Steam turbine (CCS)	Lignite	42%	40	2,700 m	3.3%	30,000	20,000
Gas turbine	Natural gas	46%	33	375 m	3.5%	25,000	17,500
Gas turbine	Biomethane	46%	33	375 m	3.5%	25,000	17,500
CCGT	Natural gas	64%	33	700 m	3.0%	120,000	60,000
CCGT	Biomethane	64%	33	700 m	3.0%	120,000	60,000
Engine power station	Natural gas	45%	25	475 m	5.5%	30,000	5,000
Engine power station	Biomethane	45%	25	475 m	5.5%	30,000	5,000
Wood power station	Biomass	38%	25	3,870 m	3.4%	70,000	35,000

TABLE 29. Default cost and technology parameters for CHP technologies in 2050. Source: [46,79,136].

Technology	ρ	η_{el}	u	c_I	$c_{O\&M}$	$c_{start,cold}$	$c_{start,warm}$
Unit	$[GW_{el}/GW_{th}]$	$[\%]$	$[years]$	$[€/GW_{el}]$	$[\%/a]$	$[€/(GW_{el} * no.)]$	$[€/(GW_{el} * no.)]$
Combined cycle	1.19	48%	33	950 m	9.0%	120,000	60,000
Gas turbine	0.63	33%	33	730 m	5.0%	25,000	17,500
Steam turbine	0.68	36%	40	1,600 m	5.0%	60,000	40,000
Industrial CHP	0.97	42%	25	750 m	9.0%	30,000	5,000

TABLE 30. Default cost and technology parameters for storage and DSM technologies in 2050. Source: [46,151].

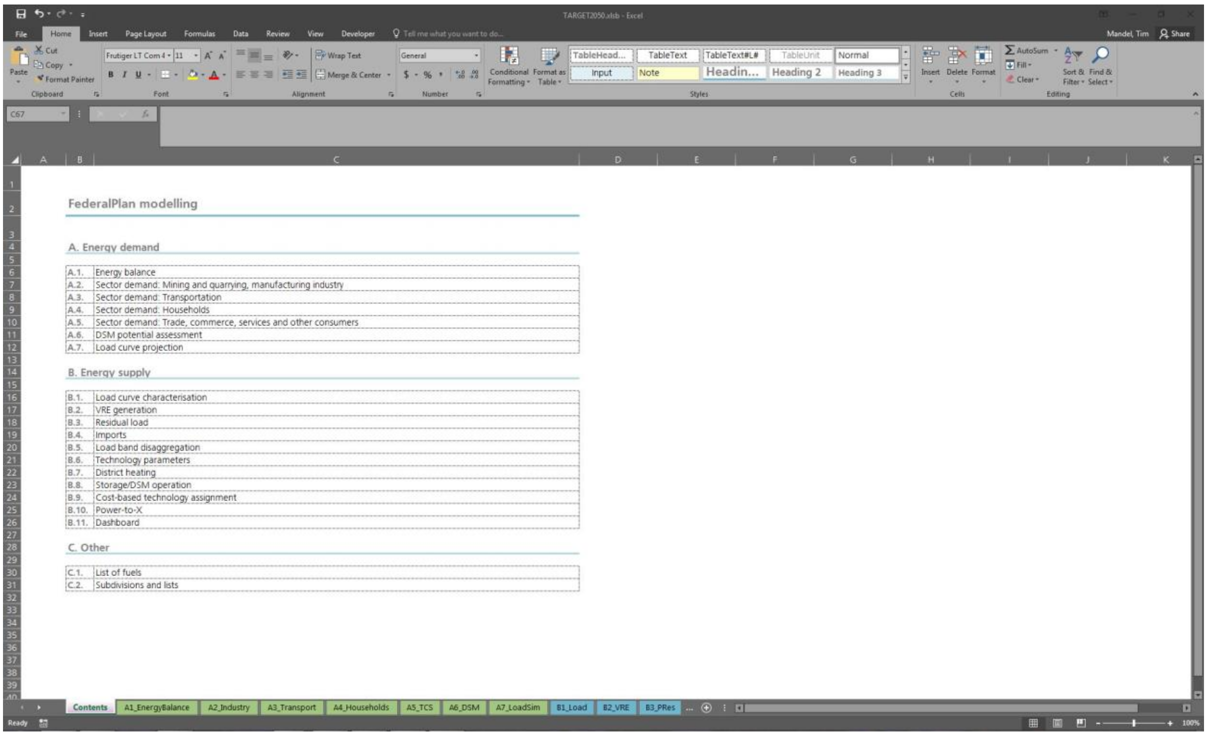
Technology	η_{charge}	c_{charge}	u_{charge}	SOC_{min}	$c_{storage}$	$u_{storage}$
Unit	$[-]$	$[€/GW_{el}]$	$[years]$	$[\%]$	$[€/GWh]$	$[years]$
Pumped hydro-electric storage	88%	412 m	40	0%	50 m	40
Adiabatic compressed air storage	87%	299 m	40	60%	23 m	40
Hydrogen storage	78%	200 m	18	35%	0.45 m	40
Methane storage (GT)	66%	800 m	25	35%	0.2 m	40
Methane storage (CCGT)	66%	800 m	25	35%	0.2 m	40
Battery storage	95%	45 m	30	0%	150 m	25
DSM	100%	25 m	10	-	-	-
Technology	$\eta_{discharge}$	$c_{discharge}$	$u_{discharge}$	$c_{O\&M}$		
Unit	$[-]$	$[€/GW_{el}]$	$[years]$	$[\%/a]$		
Pumped hydro-electric storage	89%	438 m	40	1.2%		
Adiabatic compressed air storage	78%	351 m	40	1.0%		
Hydrogen storage	58%	375 m	33	3.5%		
Methane storage (GT)	46%	375 m	33	2.5%		
Methane storage (CCGT)	64%	700 m	33	2.5%		
Battery storage	95%	0	30	1.0%		
DSM	100%	-	-	60%		

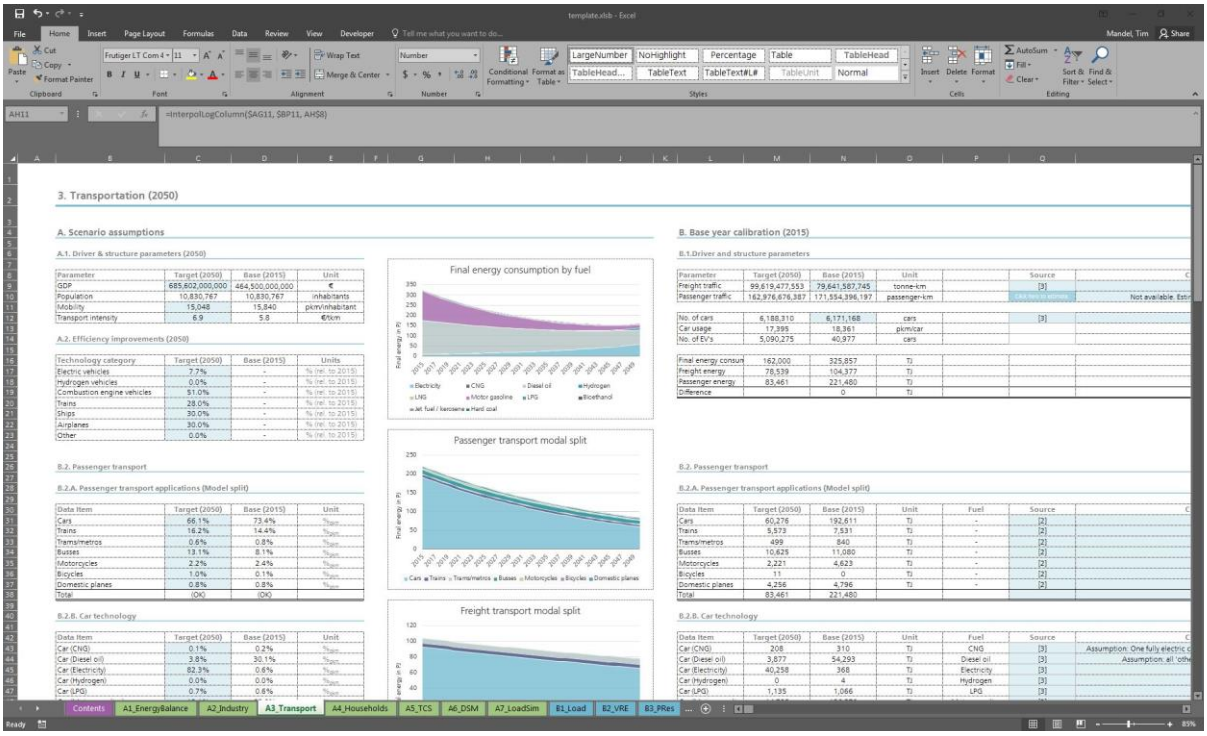
TABLE 31. Default cost and technology parameters for P2H and P2G technologies in 2050. Source: [46,151].

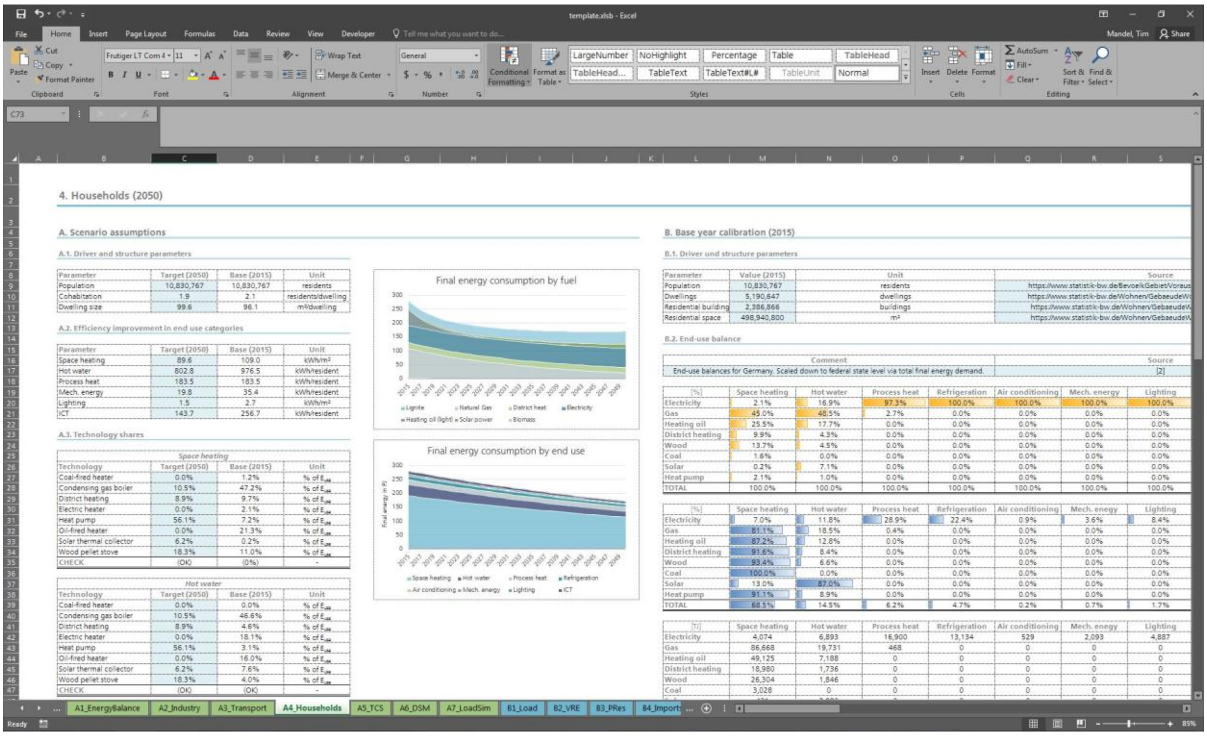
Technology	η	C_I	u	$c_{O\&M}$
Unit	$[-]$	$[€/GW_{th}]$	$[years]$	$[\%/a]$
Power-to-heat (electrode boiler)	100%	70 m	15	2.0%
Power-to-gas (electrolysis/methanisation)	66%	800 m	25	2.5%

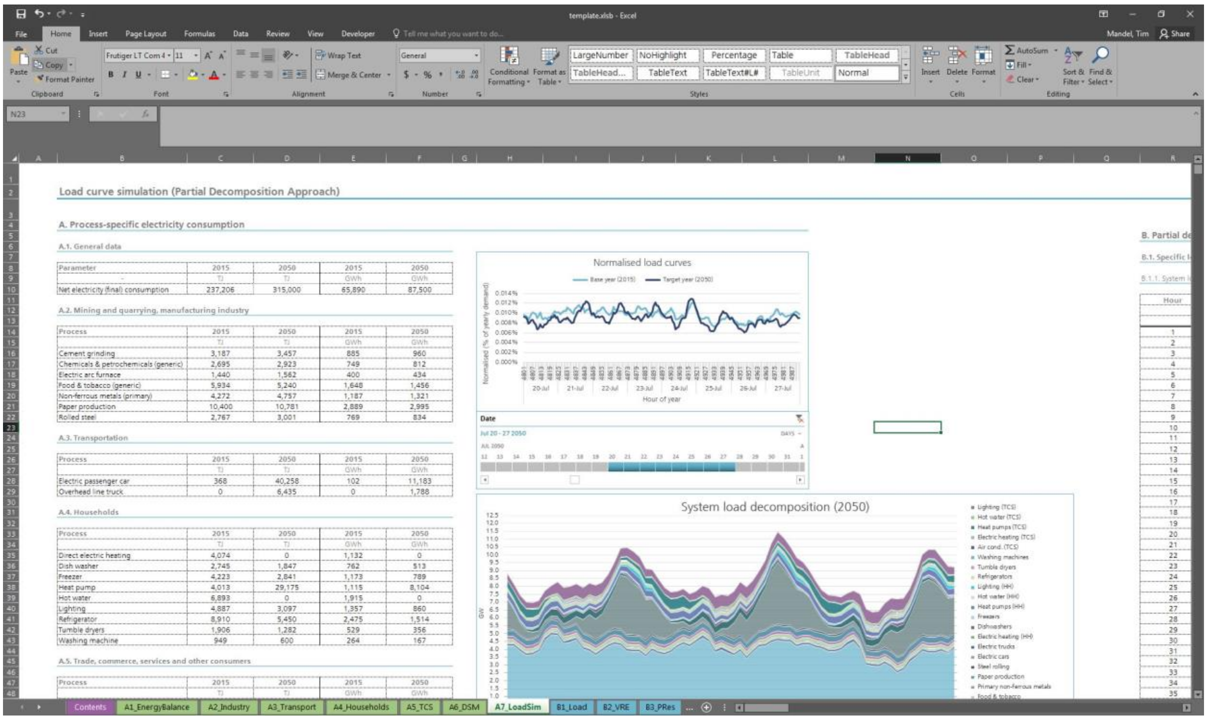
7.3. Screenshots of the FederalPlan modelling tool

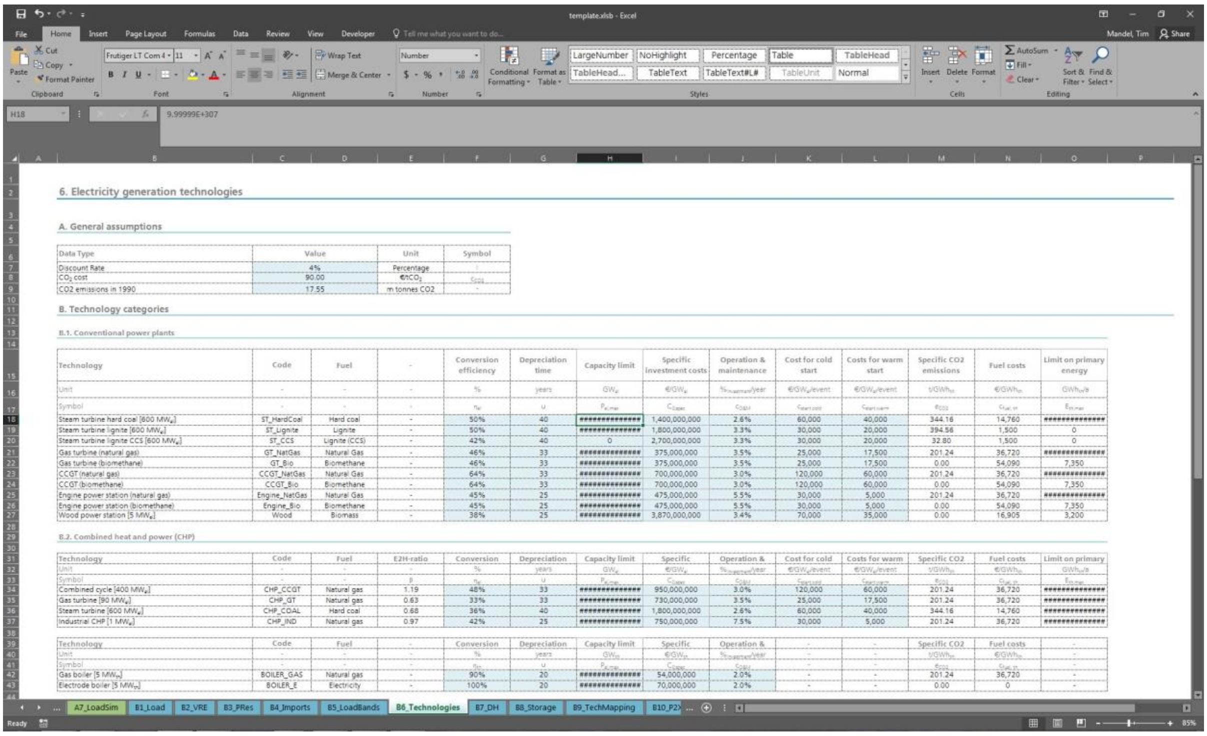
The following images are derived from the *Excel*-based implementation of the FederalPlan model. In total, the workbook includes 20 worksheets, summing up to a file size of about 120 MB.

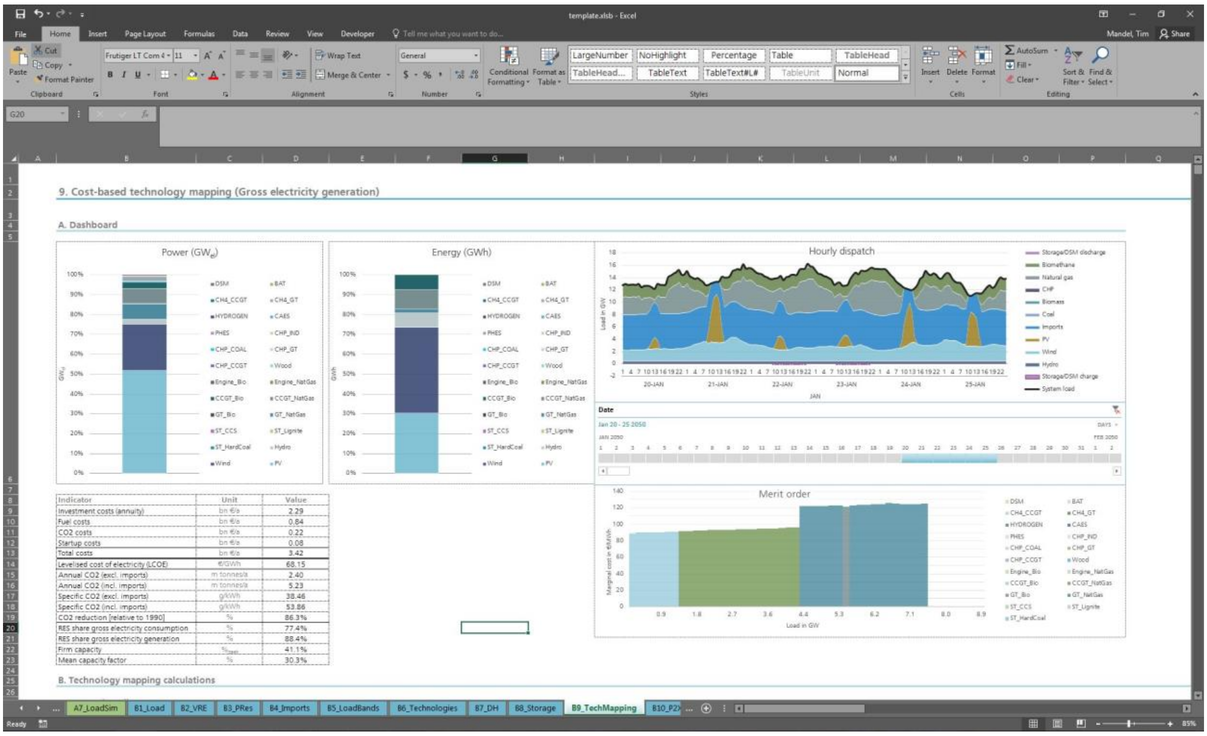





template.xlsb - Excel
4. Households (2050)
A. Scenario assumptions
A.1. Driver and structure parameters
A.2. Efficiency improvement in end use categories
A.3. Technology shares
B. Base year calibration (2015)
B.1. Driver und structure parameters
B.2. End-use balance
Final energy consumption by fuel
Final energy consumption by end use
A1_EnergyBalance
A2_Industry
A3_Transport
A4_Households
A5_TCS
A6_DSM
A7_LoadSim
B1_Load
B2_VRE
B3_PRes
B4_Import


template.xlsb - Excel
Load curve simulation (Partial Decomposition Approach)
A. Process-specific electricity consumption
A.1. General data
A.2. Mining and quarrying, manufacturing industry
A.3. Transportation
A.4. Households
A.5. Trade, commerce, services and other consumers
Normalised load curves
System load decomposition (2050)
Contents
A1_EnergyBalance
A2_Industry
A3_Transport
A4_Households
A5_TCS
A6_DSM
A7_LoadSim
B1_Load
B2_VRE
B3_PRes





7.4. Sectoral input parameters used for the comparative assessment

The following tables provide an overview of the parameters set in the FederalPlan model to approximate the demand sector developments in the BAU2050 and TARGET2050 scenarios of the BW-Report [50] (see Section 4.2). Note that the BW-Report does not provide detailed data for each of these parameters. For this reason, educated guesses were made. Especially to be emphasised is the industry sector, for which the BW-Report provides no data with regard to efficiency improvements. Accordingly, dummy values were assumed, approximating the target values in terms of electricity and district heat consumption in the target scenarios.

TABLE 32. Data sources used for calibrating final energy demand in the FederalPlan model to the case of Baden-Württemberg for the base year 2015. REG = regional/federal state data; NAT = national/Germany data.

Parameter	Regional / national data	Source
General inputs		
Energy balance	REG	[108]
Population	REG	[52]
GDP	REG	[52]
Industry sector		
Sectoral value added	REG	[52]
End-use balance	NAT	[115]
Transport sector		
Passenger car disaggregation, freight transport activity	REG	[113,158]
Modal-split for passenger and freight transport	NAT	[114]
Household sector		
No. dwellings and residential space	REG	[52]
Equipment rates	NAT	[111]
End-use balance	NAT	[109]
Tertiary sector		
Tertiary sector end-use balance	NAT	[117]
Building space	NAT	[159]

TABLE 33. Inputs to the FederalPlan model to replicate results in the industry sector from the BAU2050 and TARGET2050 scenarios. Source: author's own, based on [50].

	BAU2050 / TARGET2050							
Economic growth [rel. to 2015]								
Quarrying, other mining	-26.0%							
Food and tobacco	-8.0%							
Paper	8.0%							
Basic chemicals	13.0%							
Other chemical industry	18.0%							
Rubber and plastic products	25.0%							
Glass and ceramics	13.0%							
Mineral processing	13.0%							
Manufacture of basic metals	13.0%							
Non-ferrous metals, foundries	16.0%							
Metal processing	17.0%							
Manufacture of machinery	53.0%							
Manufacture of transport equipment	51.0%							
Other segments	40.0%							
	BAU2050							
Efficiency improvements in electricity processes [rel. to 2015]	**Space heating**	**Hot water**	**Process heat**	**Process cooling**	**Air cond.**	**Mech. Energy**	**Lighting**	**ICT**
Quarrying, other mining	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Food and tobacco	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Paper	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Basic chemicals	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Other chemical industry	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Rubber and plastic products	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Glass and ceramics	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Mineral processing	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Manufacture of basic metals	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Non-ferrous metals, foundries	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Metal processing	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Manufacture of machinery	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Manufacture of transport equipment	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Other segments	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Efficiency improvements in other fuel processes [rel. to 2015]	**Space heating**	**Hot water**	**Process heat**	**Process cooling**	**Air cond.**	**Mech. Energy**	**Lighting**	**ICT**
Quarrying, other mining	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Food and tobacco	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Paper	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Basic chemicals	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Other chemical industry	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Rubber and plastic products	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Glass and ceramics	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%

Mineral processing	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Manufacture of basic metals	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Non-ferrous metals, foundries	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Metal processing	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Manufacture of machinery	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Manufacture of transport equipment	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
Other segments	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%
TARGET2050								
Efficiency improvements in electricity processes [rel. to 2015]	**Space heating**	**Hot water**	**Process heat**	**Process cooling**	**Air cond.**	**Mech. Energy**	**Lighting**	**ICT**
Quarrying, other mining	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Food and tobacco	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Paper	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Basic chemicals	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Other chemical industry	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Rubber and plastic products	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Glass and ceramics	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Mineral processing	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Manufacture of basic metals	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Non-ferrous metals, foundries	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Metal processing	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Manufacture of machinery	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Manufacture of transport equipment	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Other segments	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Efficiency improvements in other fuel processes [rel. to 2015]	**Space heating**	**Hot water**	**Process heat**	**Process cooling**	**Air cond.**	**Mech. Energy**	**Lighting**	**ICT**
Quarrying, other mining	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Food and tobacco	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Paper	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Basic chemicals	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Other chemical industry	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Rubber and plastic products	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Glass and ceramics	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Mineral processing	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Manufacture of basic metals	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Non-ferrous metals, foundries	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Metal processing	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Manufacture of machinery	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Manufacture of transport equipment	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Other segments	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%

Table 34. Inputs to the FederalPlan model to replicate results in the transport sector from the BAU2050 and TARGET2050 scenarios. Source: author's own, based on [50].

	[2015]	BAU2050	TARGET2050
Driver & structure parameters			
GDP [€]	464,500,000,000	685,602,000,000	
Population [inhabitants]	10,830,767	10,830,767	
Mobility [pkm/inhabitant]	15,840	15,048	
Transport intensity [€/tkm]	5.8	6.9	
Efficiency improvements [rel. to 2015]			
Electric vehicles	-	5.0%	7.7%
Hydrogen vehicles	-	0.0%	0.0%
Combustion engine vehicles	-	51.0%	51.0%
Trains	-	28.0%	28.0%
Ships	-	30.0%	30.0%
Airplanes	-	30.0%	30.0%
Other	-	0.0%	0.0%
Passenger transport applications (modal split) [% pkm]			
Cars	73.4%	73.4%	66.1%
Trains	14.4%	15.5%	16.2%
Trams/metros	0.8%	0.8%	0.6%
Busses	8.1%	7.1%	13.1%
Motorcycles	2.4%	2.4%	2.2%
Bicycles	0.1%	0.1%	1.0%
Domestic planes	0.8%	0.8%	0.8%
Car technology [% pkm]			
CNG	0.2%	0.1%	0.1%
Diesel	30.1%	24.0%	3.8%
Electricity	0.6%	26.1%	82.3%
Hydrogen	0.0%	0.0%	0.0%
LPG	0.6%	0.5%	0.7%
Gasoline	68.6%	49.3%	13.1%
Train technology [% pkm]			
Diesel	8.8%	0.0%	0.0%
Electricity	91.2%	100.0%	100.0%
Hard coal	0.0%	0.0%	0.0%
Bus technology [% pkm]			
CNG	8.4%	0.9%	0.0%
Diesel	91.4%	99.1%	66.9%
Electricity	0.0%	0.0%	17.4%
Hydrogen	0.0%	0.0%	15.7%
LNG	0.0%	0.0%	0.0%
Gasoline	0.2%	0.0%	0.0%
Motorcycle technology [% pkm]			
Electricity	0.0%	0.0%	17.5%
Gasoline	100.0%	100%	82.5%
Bicycle technology [% pkm]			
Electricity	0.0%	0.0%	80.0%
None	100.0%	100.0%	20.0%
Domestic aviation technology [% pkm]			
Bioethanol	0.0%	0.0%	36.0%
Kerosene	97.5%	97.5%	64.0%
Gasoline	2.5%	2.5%	0.0%
Freight transport applications (modal split) [% tkm]			
Truck	76.8%	76.8%	66.6%
Train	15.2%	15.2%	23.5%
Ship	8.0%	8.0%	9.9%
Truck technology [% tkm]			
CNG	0.2%	0.0%	0.0%
Diesel	98.9%	100.0%	77.5%
Electricity	0.0%	0.0%	11.6%
Hydrogen	0.0%	0.0%	10.9%
LNG	0.2%	0.0%	0.0%
Gasoline	0.7%	0.0%	0.0%
Train technology [% tkm]			
Diesel	31.5%	0.0%	0.0%
Electricity	68.5%	100.0%	100.0%
Domestic navigation technology [% tkm]			
Diesel	100.0%	100.0%	100.0%
LNG	0.0%	0.0%	0.0%

TABLE 35. Inputs to the FederalPlan model to replicate results in the household sector from the BAU2050 and TARGET2050 scenarios. Source: author's own, based on [50].

	[2015]	BAU2050	TARGET2050
Driver & structure parameters			
Population [inhabitants]	10,830,767	10,830,767	
Cohabitation [inhabitants/dwelling]	2.1	1.9	
Dwelling size [m²/dwelling]	96.1	99.6	
Efficiency in end-use categories			
Space heating [kWh/m²]	109.0	101.0	89.6
Hot water [kWh/resident]	976.5	899.7	802.8
Process heat [kWh/resident]	183.5	183.5	183.5
Mech. energy [kWh/resident]	35.4	31.8	19.8
Lighting [kWh/m²]	2.7	2.3	1.5
ICT [kWh/resident]	256.7	308.0	143.7
Space heating technologies [% in useful energy]			
Coal-fired heater	1.2%	0.0%	0.0%
Condensing gas boiler	47.2%	28.9%	10.5%
District heating	9.7%	9.3%	8.9%
Electric heater	2.1%	1.1%	0.0%
Heat pump	7.2%	31.7%	56.1%
Oil-fired heater	21.3%	10.7%	0.0%
Solar thermal collector	0.2%	3.2%	6.2%
Wood pellet stove	11.0%	14.7%	18.3%
Hot water technologies [% in useful energy]			
Coal-fired heater	0.0%	0.0%	0.0%
Condensing gas boiler	46.6%	29.0%	10.5%
District heating	4.6%	7.0%	8.9%
Electric heater	18.1%	9.0%	0.0%
Heat pump	3.1%	30.0%	56.1%
Oil-fired heater	16.0%	8.0%	0.0%
Solar thermal collector	7.6%	7.0%	6.2%
Wood pellet stove	4.0%	10.0%	18.3%
Cooking technologies [% in useful energy]			
Electric stove	83.1%	81.6%	80.0%
Gas stove	2.6%	1.3%	0.0%
Induction stove	14.3%	17.2%	20.0%
White appliances [units/dwelling]			
Dish washer	0.71	0.90	0.78
Freezer	0.52	0.70	0.57
Refrigerator	1.00	1.00	1.00
Tumble dryer	0.40	0.08	0.44
Washing machine	0.97	1.00	1.00
White appliances [kW/unit]			
Dish washer	0.37	0.29	0.2
Freezer	0.15	0.12	0.08
Refrigerator	0.15	0.12	0.08
Tumble dryer	1.25	0.98	0.7
Washing machine	0.18	0.14	0.1
Air conditioning			
Equipment rate [units/dwelling]	0.04	0.10	0.16
Power per unit [kW/unit]	1.70	1.33	0.95

TABLE 36. Inputs to the FederalPlan model to replicate results in the tertiary sector from the BAU2050 and TARGET2050 scenarios. Source: author's own, based on [50].

	[2015]	BAU2050	TARGET2050
Driver & structure parameters			
Value added [€]	418,153,000,000	617,361,089,200	
Space intensity [m²/€]	0.00067	0.00048	
Efficiency in end-use categories			
Space heating [kWh/m²]	81.69	66.1	56.6
Hot water [kWh/m²]	8.91	7.7	6.4
Process heat [kWh/m²]	13.31	11.4	9.5
Refrigeration [kWh/m²]	6.36	5.4	4.5
Air conditioning [kWh/m²]	1.86	1.6	1.3
Mech. energy [kWh/m²]	34.02	29.2	24.3
Lighting [kWh/m²]	26.19	22.4	18.7
ICT [kWh/m²]	11.75	10.1	8.4
Space heating technologies [% in useful energy]			
Coal-fired heater	0.6%	0.3%	0.0%
District heating	7.8%	9.9%	12.0%
Electric heater	3.4%	1.7%	0.0%
Gas-fired heater	51.8%	37.7%	23.5%
Heat pump	0.5%	23.1%	45.8%
Oil-fired heater	23.3%	11.7%	0.0%
Solar thermal panels	0.1%	6.8%	13.6%
Biomass-fired heater	12.5%	8.8%	5.0%